NEW ISSUE – FULL BOOK-ENTRY

RATINGS
Moody's: Aa3/Fitch: AA-

In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, (a) based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, (b) interest on the 2022 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, and (c) interest on the 2022 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah. In the further opinion of Bond Counsel, interest on the 2022 Series A Bonds is not a specific preference item for purposes of the federal alternative minimum tax. Bond Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2022 Series A and B Bonds. See "TAX MATTERS" herein.

Intermountain Power Agency

Energy for Today & Tomorrow

(a political subdivision of the State of Utah)

$797,605,000
Power Supply Revenue Bonds

$732,755,000	$64,850,000
2022 Series A	**2022 Series B**
(Tax-Exempt)	**(Federally Taxable)**

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

The Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds") will be 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"). Purchases of 2022 Series A and B Bonds will be made in book-entry form only, in the principal amount of $5,000 and any integral multiples thereof, through brokers and dealers who are, or who act through, DTC participants. Semiannual interest on the 2022 Series A and B Bonds is payable each January 1 and July 1, commencing July 1, 2022, as more fully described herein. So long as DTC or its nominee is the registered owner of the 2022 Series A and B Bonds, payments of the principal of and interest on such Bonds will be made directly to DTC (see "DESCRIPTION OF THE 2022 SERIES A AND B BONDS – Book-Entry Only System" herein).

The 2022 Series A and B Bonds will be subject to redemption prior to maturity as described herein.

The 2022 Series A and B Bonds are being issued to provide a portion of the funds required to finance or refinance a portion of the Cost of Acquisition and Construction of a repowering of the Project (as such terms are defined herein), to fund a debt service reserve account, to fund capitalized interest on the 2022 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2022 Series A and B Bonds.

MATURITY SCHEDULE – See Inside Front Cover

The principal or redemption price of, and interest on, the 2022 Series A and B Bonds are payable solely from and secured solely by a pledge and assignment of the Trust Estate (as defined in the Resolution referred to herein) derived by Intermountain Power Agency (the "Agency") from the Project and other funds pledged under the Resolution, including the Revenues (as defined in the Resolution), which include all payments attributable to the Project to be made to the Agency by the Power Purchasers pursuant to the Power Sales Contracts and Renewal Power Sales Contracts referred to herein. Such payments, together with other available Revenues, are to equal the Agency's costs relating to the Project. Each municipal Power Purchaser has agreed to make its share of such payments solely from its electric system revenues and each other Power Purchaser has agreed to make its share of such payments as a general obligation. The amounts payable by the Power Purchasers under the Power Sales Contracts and Renewal Power Sales Contracts are payable whether or not the Project or any part thereof has been completed, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part.

The 2022 Series A and B Bonds will not be an obligation of the State of Utah or any political subdivision thereof, other than the Agency, nor of any member of the Agency or Power Purchaser and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both will be pledged for the payment of the 2022 Series A and B Bonds. The Agency has no taxing power.

The 2022 Series A and B Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, and certain other conditions. Certain legal matters will be passed upon for the Agency by its counsel, Holland & Hart LLP, Salt Lake City, Utah. Certain legal matters will be passed upon for the Underwriters by their counsel, Gilmore & Bell, P.C., Salt Lake City, Utah. Stifel, Nicolaus & Company, Incorporated has acted as Municipal Advisor to the Agency in connection with the 2022 Series A and B Bonds. It is expected that the 2022 Series A and B Bonds in definitive form will be available for delivery to DTC in New York, New York on or about May 12, 2022.

BofA Securities **Goldman Sachs & Co. LLC**
J.P. Morgan **RBC Capital Markets**

April 28, 2022

MATURITY SCHEDULE
INTERMOUNTAIN POWER AGENCY

$732,755,000
Power Supply Revenue Bonds,
2022 Series A (Tax-Exempt)

Dated: Date of Delivery **Due: as shown below**

Maturity (July 1)	Amount	Interest Rate	Yield	CUSIP Number*
2026	$22,280,000	5.000%	2.570%	45884AZX4
2027	23,395,000	5.000	2.660	45884AZY2
2028	24,565,000	5.000	2.760	45884AZZ9
2029	25,795,000	5.000	2.870	45884AA29
2030	27,085,000	5.000	2.940	45884AA37
2031	28,435,000	5.000	3.010	45884AA45
2032	29,860,000	5.000	3.090†	45884AA52
2033	31,350,000	5.000	3.180†	45884AA60
2034	32,920,000	5.000	3.240†	45884AA78
2035	34,565,000	5.000	3.310†	45884AA86
2036	36,295,000	4.000	3.570†	45884AA94
2037	37,745,000	5.000	3.370†	45884AB28
2038	39,635,000	5.000	3.410†	45884AB36
2039	41,615,000	5.000	3.440†	45884AB44
2040	43,695,000	5.000	3.450†	45884AB51
2041	45,880,000	5.000	3.460†	45884AB69
2042	48,175,000	5.000	3.480†	45884AB77
2043	50,585,000	5.000	3.500†	45884AB85
2044	53,110,000	5.000	3.520†	45884AB93
2045	55,770,000	5.000	3.530†	45884AC27

$64,850,000
Power Supply Revenue Bonds,
2022 Series B (Federally Taxable)

Dated: Date of Delivery **Due: as shown below**

$31,640,000 Serial Bonds

Maturity (July 1)	Amount	Interest Rate	Price	CUSIP Number*
2026	$ 2,120,000	3.496%	100%	45884AC35
2027	2,190,000	3.646	100	45884AC43
2028	2,270,000	3.780	100	45884AC50
2029	2,355,000	3.830	100	45884AC68
2030	2,450,000	3.905	100	45884AC76
2031	2,545,000	4.055	100	45884AC84
2032	2,645,000	4.155	100	45884AC92
2033	2,755,000	4.305	100	45884AD26
2034	2,875,000	4.455	100	45884AD34
2035	3,005,000	4.605	100	45884AD42
2036	3,140,000	4.705	100	45884AD59
2037	3,290,000	4.805	100	45884AD67

$33,210,000 5.25% Term Bonds due July 1, 2045 – to Yield 5.012%‡ (CUSIP No. 45884AD75*)

(Without Accrued Interest)

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* CUSIP® is a registered trademark of the American Bankers Association. CUSIP data herein is provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of The American Bankers Association. This information is not intended to create a database and does not serve in any way as a substitute for the CUSIP Services Bureau. CUSIP numbers have been assigned by an independent company not affiliated with the Agency or the Underwriters and are included solely for the convenience of the registered owners of the applicable 2022 Series A and B Bonds. Neither the Agency nor the Underwriters are responsible for the selection or uses of these CUSIP numbers, and no representation is made as to their correctness on the applicable 2022 Series A and B Bonds or as included herein. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2022 Series A and B Bonds as a result of various subsequent actions including, but not limited to, a refunding in whole or in part or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2022 Series A and B Bonds.

† Yield to optional par call on July 1, 2031.

‡ Yield to optional par call on July 1, 2032.

INTERMOUNTAIN POWER AGENCY
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Board of Directors

Blaine J. Haacke – Chair

Nick Tatton
Allen Johnson
Mark Montgomery
Eric Larsen
Joel Eves
Bruce Rigby

Management

Cameron R. Cowan – General Manager
Vance K. Huntley – Treasury Manager
Linford E. Jensen – Accounting Manager
Cody Combe – Audit Manager

Power Purchasers

Utah

Beaver City*
City of Bountiful*
Bridger Valley Electric Association, Inc.*
Dixie-Escalante Rural Electric Association, Inc.*
City of Enterprise*
Ephraim City*
City of Fairview*
Fillmore City*
Flowell Electric Association, Inc.*
Garkane Energy Cooperative, Inc.*
Heber Light & Power Company*
Holden Town*
City of Hurricane*
Hyrum City*
Kanosh Town*
Kaysville City*
Lehi City*
City of Logan*
Meadow Town
Monroe City
Moon Lake Electric Association, Inc.*
Morgan City*
Mt. Pleasant City*
Mt. Wheeler Power, Inc.*
Murray City*
Town of Oak City*
Parowan City*
Price City*
Spring City*

California

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

* Renewal Power Purchaser

Coordinating Committee

Chairman – Cameron R. Cowan

Power Purchaser(s) Represented	Representative
Murray City	Blaine J. Haacke
City of Logan	Mark Montgomery
All Other Utah Municipal Purchasers	Eric Larsen
Moon Lake Electric Association, Inc.	Yankton Johnson
Mt. Wheeler Power, Inc.	Kevin Robison
All Other Cooperative Purchasers	LaDel Laub

Power Purchaser Represented	Representative
Department of Water and Power of The City of Los Angeles	Paul R .Schultz
City of Anaheim	Dukku Lee
City of Burbank	Dawn Roth Lindell
City of Glendale	Chie Valdez
City of Pasadena	Shari Thomas (alt.)
City of Riverside	Todd M. Corbin

Trustee, Bond Registrar and Paying Agent

The Bank of New York Mellon
Woodland Park, New Jersey

Project Manager and Operating Agent

Department of Water and Power of The City of Los Angeles

Counsel to the Agency

Holland & Hart LLP
Salt Lake City, Utah

Bond Counsel to the Agency

Orrick, Herrington & Sutcliffe LLP
New York, New York

Municipal Advisor

Stifel, Nicolaus & Company, Incorporated
Salt Lake City, Utah

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SUMMARY

The following summary does not purport to be complete and is qualified in its entirety by, and should be read in conjunction with, the more detailed information appearing elsewhere in this Official Statement and any supplement or amendment hereto. Capitalized terms used in this Summary and not defined herein have the meanings given to such terms elsewhere in this Official Statement.

Issuer ..... Intermountain Power Agency (the "Agency") is a political subdivision of the State of Utah. The Agency has acquired and constructed and is operating the Intermountain Power Project (the "Project"), which consists of, among other things, (i) a two-unit coal-fired steam-electric generating plant with a net rating of 1,800 MW 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"), (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"). The operation and maintenance of the Project are being managed for the Agency by the Department of Water and Power of The City of Los Angeles (the "Department") in its capacity as Operating Agent.

The Agency is undertaking the replacement of the generation facilities of the Project, to consist of the construction and installation of gas-fueled power blocks to replace the coal-fired units, with commercial operation of the gas units to be achieved by July 1, 2025 (sometimes referred to herein as the "Gas Repowering"), along with (a) the development of capability to burn a mix of natural gas and hydrogen fuel in the gas units (the "Hydrogen Betterments") and (b) the entry into contracts with third parties to provide services for (i) natural gas transportation (the "Natural Gas Transportation Contract") and (ii) conversion of water into hydrogen using renewable energy and the storage of such hydrogen (the "Hydrogen Conversion and Storage Capacity" and together with the Hydrogen Betterments, collectively, the "Hydrogen Facilities"). The Gas Repowering, together with Natural Gas Transportation Contract and the development of the Hydrogen Facilities, are referred to herein collectively as the "Generation Renewal Project".

Concurrently with the Generation Renewal Project, the Agency also is undertaking the replacement, renewal, and expansion of certain facilities of the Southern Transmission System to provide for an extension of the useful life thereof (as more fully described herein, the "STS Renewal Project"). The cost of acquisition and construction of the STS Renewal Project is expected to be paid from payments-in-aid of construction to be made to the Agency by the Southern California Public Power Authority ("SCPPA") from the proceeds of bonds or other obligations of SCPPA to be issued for such purpose. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" herein.) As a result, it is not anticipated that such cost of acquisition and

construction of the STS Renewal Project will be paid from the proceeds of the Agency's Bonds (including the 2022 Series A and B Bonds) or other obligations.

The 2022 Series A and B Bonds..... The $732,755,000 Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds") are being offered in the principal amount per maturity and bearing the interest rates set forth on the inside cover page of this Official Statement.

The 2022 Series A and B Bonds will be issued pursuant to the Agency's Power Supply Revenue Bond Resolution adopted on September 28, 1978, as heretofore supplemented, amended and restated (the "Resolution"), including as supplemented and amended by the Agency's Sixty-First Supplemental Power Supply Revenue Bond Resolution relating to the 2022 Series A and B Bonds adopted on April 28, 2022 (the "Sixty-First Supplemental Resolution").

All of the Bonds previously issued under the Resolution heretofore have been paid at maturity, redeemed or deemed to have been paid within the meaning and effect of the Resolution. As a result, upon the issuance of the 2022 Series A and B Bonds, the 2022 Series A and B Bonds will be the only Bonds Outstanding under (and as defined in) the Resolution.

Denominations..... The 2022 Series A and B Bonds are issuable in the denominations of $5,000 or any integral multiple thereof.

Interest Payment Dates..... Interest on the 2022 Series A and B Bonds shall be calculated on the basis of a 360-day year consisting of twelve 30-day months payable on each January 1 and July 1, commencing on July 1, 2022.

Redemption..... The 2022 Series A and B Bonds are subject to optional and mandatory redemption on the dates and at the redemption prices described herein under the caption "DESCRIPTION OF THE 2022 SERIES A AND B BONDS — Redemption" herein.

Plan of Finance..... The proceeds of the 2022 Series A and B Bonds will provide a portion of the funds required to finance or refinance a portion of the Cost of Acquisition and Construction (as defined in the Resolution) of the Gas Repowering, including the refunding of $100,000,000 in aggregate principal amount of the Agency's outstanding Subordinated Power Supply Revenue Bonds, 2019 Drawdown Series (the "Refunded Subordinated Bonds") heretofore issued to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering (see "INTRODUCTORY STATEMENT – The Project and the Generation Renewal Project" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Generation Renewal Project" herein), to fund a debt service reserve account, to fund capitalized interest on the 2022 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2022 Series A and B Bonds. See "PLAN OF FINANCING" herein.

Security for the 2022 Series A and B Bonds..... The principal or redemption price of, and interest on, the Bonds (including the 2022 Series A and B Bonds) is payable from and secured by the Trust

Estate (as defined in "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Pledge Effected by the Resolution" herein). For a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Additional Bonds" herein.

The principal of, and interest on, the 2022 Series A and B Bonds also is payable from and secured by the amounts on deposit in the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Resolution as may from time to time be available therefor (including the investments held as a part of such Account). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Initial Subaccount in Debt Service Reserve Account" herein.

Pursuant to the Sixty-First Supplemental Resolution, the Agency is required to deposit and maintain, or cause to be deposited and maintained, in the Initial Subaccount moneys and Investment Securities in an amount equal to the Initial Subaccount Debt Service Reserve Requirement. The term "Initial Subaccount Debt Service Reserve Requirement" is defined in the Sixty-First Supplemental Resolution to mean, as of any date of calculation, an amount equal to the greatest amount of Aggregate Debt Service (as defined in the Resolution) on all Bonds of each Additionally Secured Series secured by the Initial Subaccount for the then current or any future Fiscal Year. Upon the issuance of the 2022 Series A and B Bonds, the Initial Subaccount Debt Service Reserve Requirement will be funded from a portion of the proceeds of the 2022 Series A and B Bonds.

See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS" herein.

Registration of the 2022 Series A and B Bonds... The 2022 Series A and B Bonds will be issuable as fully registered bonds in the name of Cede & Co., as nominee of The Depository Trust Company ("DTC"). No person acquiring an interest in the 2022 Series A and B Bonds (a "Beneficial Owner") will be entitled to receive a 2022 Series A or B Bond in certificated form, except under the limited circumstances described in this Official Statement in "DESCRIPTION OF THE 2022 SERIES A AND B BONDS – Book-Entry Only System" herein. All references to actions by Holders of the 2022 Series A and B Bonds will refer to actions taken by DTC, upon instructions from DTC Participants, and all references herein to distributions, notices, reports and statements to Holders shall refer to distributions, notices, reports and statements, respectively, to DTC or Cede & Co., as the registered owner of the 2022 Series A and B Bonds, or to DTC Participants for distribution to Beneficial Owners in accordance with DTC procedures. See "DESCRIPTION OF THE 2022 SERIES A AND B BONDS – Book-Entry Only System" herein.

Tax Considerations ..... In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, (a) based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2022 Series A Bonds is excluded from

	gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, (b) interest on the 2022 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, and (c) interest on the 2022 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah. In the further opinion of Bond Counsel, interest on the 2022 Series A Bonds is not a specific preference item for purposes of the federal alternative minimum tax. Bond Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2022 Series A and B Bonds. See "TAX MATTERS" herein.
Trustee	The Bank of New York Mellon, Woodland Park, New Jersey.
Agency's Municipal Advisor	Stifel, Nicolaus & Company, Incorporated, Salt Lake City, Utah. See "MUNICIPAL ADVISOR" herein.
Ratings	Moody's Investors Services, Inc. has assigned a rating of "Aa3" and a stable ratings outlook to the 2022 Series A and B Bonds and Fitch Ratings has assigned a rating of "AA-" and a stable ratings outlook to the 2022 Series A and B Bonds. See "RATINGS" herein.

No dealer, broker, salesman or other person has been authorized by Intermountain Power Agency 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 Agency 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 2022 Series A and B Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

The information set forth herein has been furnished by the Agency, the Department of Water and Power of The City of Los Angeles and certain Power Purchasers 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 Agency, the Power Purchasers or any other person or entity discussed herein since the date hereof.

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

THE 2022 SERIES A AND B BONDS OFFERED HEREBY HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION NOR HAS THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION PASSED UPON THE ACCURACY OF THIS OFFICIAL STATEMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

None of the information on the Agency's website is included by reference herein.

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OFFICIAL STATEMENT

RELATING TO

INTERMOUNTAIN POWER AGENCY

(a political subdivision of the State of Utah)

$797,605,000
Power Supply Revenue Bonds

$732,755,000	**$64,850,000**
2022 Series A	**2022 Series B**
(Tax-Exempt)	**(Federally Taxable)**

INTRODUCTORY STATEMENT

General

The purpose of this Official Statement (which includes the cover page and inside cover page hereof and the Appendices hereto) is to provide information concerning (i) Intermountain Power Agency (the "Agency"), a political subdivision of the State of Utah (the "State"), (ii) the Intermountain Power Project (the "Project"), and (iii) the Agency's $732,755,000 Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds").

The Agency is issuing the 2022 Series A and B Bonds under the provisions of the Utah Interlocal Cooperation Act contained in Title 11, Chapter 13, Utah Code Annotated 1953, as amended (the "Act"), and the Agency's Power Supply Revenue Bond Resolution adopted on September 28, 1978, as heretofore supplemented, amended and restated (the "Resolution"), including as supplemented and amended by the Agency's Sixty-First Supplemental Power Supply Revenue Bond Resolution relating to the 2022 Series A and B Bonds adopted on April 28, 2022 (the "Sixty-First Supplemental Resolution").

The 2022 Series A and B Bonds are being offered to provide a portion of the funds required to finance or refinance a portion of the Cost of Acquisition and Construction (as defined in the Resolution) of the Gas Repowering (as hereinafter defined; see "The Project and the Generation Renewal Project" below), including the refunding of $100,000,000 in aggregate principal amount of the Agency's outstanding Subordinated Power Supply Revenue Bonds, 2019 Drawdown Series (the "Refunded Subordinated Bonds") heretofore issued to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering, to fund a debt service reserve account, to fund capitalized interest on the 2022 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2022 Series A and B Bonds.

All of the Bonds previously issued under the Resolution heretofore have been paid at maturity, redeemed or deemed to have been paid within the meaning and effect of the Resolution. As a result, upon the issuance of the 2022 Series A and B Bonds, the 2022 Series A and B Bonds will be the only Bonds Outstanding under (and as defined in) the Resolution.

The 2022 Series A and B Bonds will constitute obligations of the Agency issued under the Resolution on a senior lien basis as to security and source of payment and will rank equally and be on a parity as to security and source of payment with other Bonds which the Agency may issue hereafter. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS" herein. For

a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Additional Bonds" herein.

The Bank of New York Mellon, Woodland Park, New Jersey (the "Trustee") serves as Trustee under the Resolution for the Bonds, including, without limitation, the 2022 Series A and B Bonds. It has also been appointed as Paying Agent and Bond Registrar for the 2022 Series A and B Bonds pursuant to the Sixty-First Supplemental Resolution.

Security for the 2022 Series A and B Bonds

The principal or redemption price of, and interest on, the Bonds (including the 2022 Series A and B Bonds) is payable from and secured by the Trust Estate (as defined in "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Pledge Effected by the Resolution" herein). For a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Additional Bonds" herein.

The principal of, and interest on, the 2022 Series A and B Bonds also is payable from and secured by the amounts on deposit in the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Resolution as may from time to time be available therefor (including the investments held as a part of such Account). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Initial Subaccount in Debt Service Reserve Account" herein.

The Agency

The Agency was organized in June 1977 by 23 Utah municipalities under the Act pursuant to the Intermountain Power Agency Organization Agreement. See "INTERMOUNTAIN POWER AGENCY" herein.

The Power Purchasers and Renewal Power Purchasers

The Agency has sold the entire capability of the Project through June 15, 2027 to 35 entities (the "Power Purchasers") on a "take-or-pay" basis pursuant to separate power sales contracts between the Agency and each Power Purchaser (which power sales contracts, as amended, are referred to herein as the "Power Sales Contracts"). The Power Purchasers are 35 utilities 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 (collectively, the "California Purchasers"); the 23 members of the Agency (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" and, together with the Utah Municipal Purchasers, collectively, the "Utah Purchasers"). The California Purchasers, the Utah Municipal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Power Sales Contracts, to purchase 78.943%, 14.040% and 7.017%, respectively, of the net capability of the Generation Station. For information regarding the Department and Anaheim (the Department and Anaheim being the only Power Purchasers having responsibility for in excess of 10% of the costs of the Project under the Power Sales Contracts), see APPENDICES E and F hereto, respectively. In addition, the audited financial statements of the Department and Anaheim for the fiscal years ended June 30, 2021 and 2020 may be obtained from the Electronic Municipal Market Access ("EMMA") website of the Municipal Securities Rulemaking Board (the "MSRB"), currently located at https://emma.msrb.org. For information regarding the respective rights, duties and obligations of the Power Purchasers under the Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Power Sales Contracts" herein.

The Agency has sold the entire capability of the Project for the period beginning on June 16, 2027 (the "Transition Date") and ending on June 15, 2077 to 30 entities (the "Renewal Power Purchasers") on a

"take-or-pay" basis pursuant to separate renewal power sales contracts between the Agency and each Renewal Power Purchaser (which renewal power sales contracts, as amended, are referred to herein as the "Renewal Power Sales Contracts"). The Renewal Power Purchasers are 30 utilities consisting of the Department and the California cities of Burbank and Glendale (collectively, the "California Renewal Purchasers"); the 21 entities that will remain as members of the Agency from and after June 16, 2027 (collectively, the "Utah Municipal Renewal Purchasers"); and the six Cooperative Purchasers (together with the Utah Municipal Renewal Purchasers, collectively, the "Utah Renewal Purchasers"). The California Renewal Purchasers, the Utah Municipal Renewal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Renewal Power Sales Contracts, to purchase 78.943%, 13.975% and 7.082%, respectively, of the net capability of the Generation Station. For information regarding the respective rights, duties and obligations of the Renewal Power Purchasers under the Renewal Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Renewal Power Sales Contracts" herein.

Pursuant to the Excess Power Sales Agreement referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Excess Power Sales Agreement" herein (as amended, the "Excess Power Sales Agreement"), through June 15, 2027, the Utah 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 any portion of any such entitlement that a Utah Purchaser has, from time to time, recalled under the Excess Power Sales Agreement. So long as no such recall is in effect, the California Purchasers are committed to take or pay for 100% of the capability of the Generation Station, *provided, however*, the Utah Purchasers remain, and will remain, primarily obligated to the Agency under their respective Power Sales Contracts to pay for the Project capability they have sold to the Excess Power Purchasers, but are discharged from such obligation to the extent the Excess Power Purchasers make payments to the Agency on their behalves pursuant to the Excess Power Sales Agreement. However, to the extent set forth in the table below entitled "Percentages of Capability of Generation Station to be Purchased," certain of the Utah Purchasers have recalled portions of their entitlements to the use of the capability of the Project. While such recall, or any recall that the Utah Purchasers may elect to make hereafter, is in effect, the percentage of the capability of the Generation Station that the Excess Power Purchasers 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 each recalling Utah Purchaser will be the only Power Purchaser committed to take or pay for the percentage of capability so recalled by such Power Purchaser. The Utah Purchasers may, subject to the lead times and other requirements of the Excess Power Sales Agreement, recall from the Excess Power Purchasers all or any portion of their aggregate 21.057% entitlements to the use of the capability of the Project.

Recalls under the Excess Power Sales Agreement are made with respect to a "Summer Season" or a "Winter Season" (each a "Season"). The Excess Power Sales Agreement defines a "Summer Season" as each period beginning on March 25 and ending on the following September 24 and a "Winter Season" as each period beginning on September 25 and ending on the following March 24.

Based on the current schedules of power to be sold under the Excess Power Sales Agreement, which schedules are revised annually: (i) the recalling Utah Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, until March 24, 2023, their Project capability in excess of that which they have recalled; (ii) certain of the recalling Utah Purchasers have recalled Project capability for various Seasons between March 25, 2022 and March 24, 2027, and may recall all or any portion of their remaining Project capability for those Seasons and also may recall all or any portion of their Project capability for Seasons thereafter until the term of the Excess Power Sales Agreement ends, subject to their compliance with the recall requirements thereof; and (iii) the remaining Utah Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, until March 24, 2023, their entire Project capability, but may recall, subject to their compliance with the recall requirements of the Excess Power Sales Agreement, all or any portion of their Project capability for any Season thereafter until the term of the Excess Power Sales Agreement ends.

For a description of the obligations of the respective Power Purchasers to take or pay for capability of the Project, and the rights of the Utah Purchasers to recall capability of the Project, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" below and "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in APPENDIX B hereto.

The following table sets forth, as percentages, the capability of the Generation Station that each California Purchaser and the Utah Municipal Purchasers and the Cooperative Purchasers that have recalled such capability are obligated to purchase and pay for from and after March 25, 2022. The table is based on: (i) the percentage each California Purchaser purchases under its Power Sales Contract and, as to the Excess Power Purchasers, the capability of the Generation Station each is presently committed to purchase under the Excess Power Sales Agreement; and (ii) 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. See "POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT – Excess Entitlement Shares" in APPENDIX B hereto.

Percentages of Capability of
Generation Station to be Purchased

Power Purchaser	Winter Season beginning 25 Sep 2022	All Other Winter Seasons	Summer Season beginning 25 Mar 2022	All Other Summer Seasons
The Department	65.324%	65.971%	62.324%	65.795%
Anaheim	13.225	13.225	13.225	13.225
Riverside	7.617	7.617	7.617	7.617
Pasadena	5.872	5.929	5.609	5.913
Burbank	4.103	4.131	3.972	4.124
Glendale	2.165	2.183	2.082	2.178
Utah Municipal Purchasers	0.750	0.000	3.302	0.204
Cooperative Purchasers	0.944	0.944	1.869	0.944

Pursuant to the Agreement for Sale of Renewal Excess Power referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Agreement for Sale of Renewal Excess Power" herein, for 50 years from and after the Transition Date, the Utah Renewal Purchasers have sold to the Department their entitlements to the use of the capability of the Project except for any portion of any such entitlement that a Utah Renewal Purchaser may, from time to time, recall under the Agreement for Sale of Renewal Excess Power. See "RENEWAL POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR THE SALE OF RENEWAL EXCESS POWER – Excess Entitlement Shares" in APPENDIX B hereto.

The Project and the Generation Renewal Project

The Agency has acquired and constructed and is operating the Project, which 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"), (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"). The operation and maintenance of the Project are being managed for the Agency by the Department in its capacity as Operating Agent.

All of the facilities of the Project have been in full commercial operation since May 1, 1987. See "PROJECT OPERATIONS – Management and Operation of the Project" herein for a description of the operating history of the Project.

The Project facilities have, generally, operated with a high degree of availability, exceeding the national average of coal-fired generating units of comparable size. In recent years, primarily due to market conditions, system demand, relatively low natural gas prices and the GHG Cost Factor (hereinafter defined), the Project has been noncompetitive relative to other resources available to the California Purchasers and, as a result, the Project has operated at less than industry-average capacity levels. Neither the Agency nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations of the coal units through the commercial operation date of the natural gas units scheduled for July 1, 2025.

Further to the Agency's strategic planning initiatives (i) in 2015, the Agency and the Power Purchasers amended the Power Sales Contracts to provide, among other things, for the repowering of the Project to consist of gas-fueled power blocks to replace the coal-fired units, with commercial operation of the gas units to be achieved by July 1, 2025 (such amendments to the Power Sales Contracts are hereinafter referred to as the "Power Sales Contracts Amendments, and such repowering of the Project is referred to in the Power Sales Contracts Amendments as the "Gas Repowering"); and (ii) the Coordinating Committee established pursuant to the Power Sales Contracts (the "Coordinating Committee") (see "COORDINATING COMMITTEE" herein) and the Agency's Board of Directors have approved (a) the development of capability to burn a mix of natural gas and hydrogen fuel in the gas units (the "Hydrogen Betterments"), along with (b) the entry into contracts with third parties to provide services for (i) natural gas transportation through 2045 (the "Natural Gas Transportation Contract"), and (ii) conversion of water into hydrogen using renewable energy and the storage of such hydrogen, with the facilities necessary to provide such services (the "Hydrogen Conversion and Storage Capacity" and together with the Hydrogen Betterments, collectively, the "Hydrogen Facilities") to be substantially complete by October 1, 2024. The Gas Repowering, including the Natural Gas Transportation Contract together with the development of the Hydrogen Facilities, including the Hydrogen Conversion and Storage Capacity, are referred to herein collectively as the "Generation Renewal Project"). Concurrently with the Generation Renewal Project, the Agency also is undertaking the replacement, renewal, and expansion of certain facilities of the Southern Transmission System to provide for an extension of the useful life thereof (as more fully described herein, the "STS Renewal Project").

Following the effectiveness of the Renewal Power Sales Contracts, the Department, in its capacity as a Power Purchaser, requested, and the Project's governing bodies approved, a reduction in the design capacity and changes in the configuration of the natural gas facilities contemplated by the Power Sales Contracts Amendments (known under such contracts as an "Alternative Repowering"). Upon the effectiveness of the Alternative Repowering, the Power Sales Contracts were revised as necessary to describe the Alternative Repowering. Such revisions provide for the construction of two combined-cycle natural gas-fired power blocks, each power block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW, where "net generation capability" means gross power generation less auxiliary load for generation and transmission support. See "ELECTRIC INDUSTRY RESTRUCTURING – California Electric Energy Actions – *California Political Environment*," "ENVIRONMENTAL AND HEALTH FACTORS

AFFECTING THE ELECTRIC UTILITY INDUSTRY – California Greenhouse Gas Initiatives," "SECURITY AND SOURCES OF PAYMENT FOR 2022 SERIES A AND B BONDS – Generation Renewal Project" and "INTERMOUNTAIN POWER AGENCY – The Interlocal Cooperation Act" below.

Hydrogen Facilities

The costs of the Hydrogen Facilities (consisting of the Hydrogen Betterments and the Hydrogen Production and Storage Capacity) are being funded by the Power Purchasers to the extent such elect to facilitate the development of such facilities. The costs of the Hydrogen Betterments are and some of the initial costs of the Hydrogen Production and Storage Capacity have been funded by payments to a "Hydrogen Betterments Fund" established by and funded pursuant to resolutions adopted by the Coordinating Committee, the Renewal Contract Coordinating Committee established pursuant to the Renewal Power Sales Contracts (the "Renewal Contract Coordinating Committee") (see "RENEWAL CONTRACT COORDINATING COMMITTEE" herein) and the Agency. The balance of the costs of the Hydrogen Production and Storage Capacity are being funded pursuant to the Hydrogen Billing Procedure described below. The Department and the Cities of Burbank and Glendale are the only Power Purchasers that have elected to make payments to the Hydrogen Betterments Fund. The Agency bills those Power Purchasers for such payments on a monthly basis. The Hydrogen Betterments Fund is not a fund or account established pursuant to the Resolution and, therefore, is not a part of the Trust Estate, nor is it pledged as security for the payment of the Bonds (including the 2022 Series A and B Bonds).

In addition, on March 3, 2022, the Coordinating Committee, the Renewal Contract Coordinating Committee and the Agency approved a Hydrogen Billing Procedure that provides for the Department and any other Power Purchaser that elects to become a Hydrogen Purchaser (as defined in the Hydrogen Billing Procedure) to pay all of the costs associated with the hydrogen capabilities of the Project (including fixed costs for the Hydrogen Conversion and Storage Capacity and the variable costs of the hydrogen conversion and storage services). The costs for the Hydrogen Conversion and Storage Capacity and the variable costs for the use of such are estimated to be approximately $3,300,000,000 during the term of the contracts providing for such capacity and services, which is expected to be approximately 30 years. The costs addressed under the Hydrogen Billing Procedure represent costs that are not included in Monthly Power Costs (as defined in the Power Sales Contracts). The Hydrogen Billing Procedure provides for a reserve of $60,000,000 to be funded at a rate of $5,000,000 per month beginning in the Agency's fiscal year commencing on July 1, 2022. The Hydrogen Billing Procedure provides that the Hydrogen Purchasers will procure their hydrogen fuel from the Agency and that the Agency may condition such procurement on the execution of a fuel procurement contract between the Agency and each Hydrogen Purchaser which fuel procurement contracts would require approval of the Hydrogen Purchasers' respective governing bodies.

STS Renewal Project

The Coordinating Committee and the Agency also have approved a capital improvement plan for the Southern Transmission System consisting of the replacement, renewal, and expansion of AC switchyards, reactive power equipment and associated facilities at the Adelanto Converter Station and the Intermountain Converter Station (collectively, the "STS Renewal Project"), the Cost of Acquisition and Construction for which is expected to be funded through payments-in-aid of construction to be made by the Southern California Public Power Authority ("SCPPA") to the Agency from the proceeds of bonds or other obligations of SCPPA to be issued for such purpose, for the benefit of the California Purchasers. See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" herein. As a result, it is not anticipated that such Cost of Acquisition and Construction of the STS Renewal Project will be paid from the proceeds of the Agency's Bonds (including the 2022 Series A and B Bonds) or other obligations. The Agency will, however, be responsible for funding a portion of the shared costs incurred with respect to both the Gas Repowering and the STS Renewal Project.

Continuing Disclosure Undertaking

In order to satisfy the requirements of paragraph (b)(5) of Rule 15c2-12 ("Rule 15c2-12") promulgated by the United States Securities and Exchange Commission (the "SEC"), the Agency's Board of Directors has elected to cause the 2022 Series A and B Bonds to constitute "Covered Bonds" for purposes of a resolution adopted by the Agency's Board of Directors concurrently with the authorization of the issuance of the 2022 Series A and B Bonds entitled "Master Resolution (2022) as to the Provision of Certain Continuing Disclosure Information With Respect to Certain Designated Series of IPA Bonds" (the "Continuing Disclosure Resolution"), a copy of which is attached hereto as APPENDIX H.

Under the Continuing Disclosure Resolution, the Agency has covenanted for the benefit of the Holders and the "Beneficial Owners" (as defined in the Continuing Disclosure Resolution) of the 2022 Series A and B Bonds to provide a report (each, an "Annual Filing") containing certain financial information and operating data relating to the Agency, the Department and Anaheim by not later than nine months after the end of each of the Agency's fiscal years (presently, by each March 31), and to provide notices of the occurrence of certain enumerated events with respect to the 2022 Series A and B Bonds (each, an "Event Notice"). Each Annual Filing and each Event Notice will be filed by or on behalf of the Agency with the MSRB. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the MSRB's EMMA website, currently located at https://emma.msrb.org. The information to be contained in each Annual Filing and each Event Notice is set forth in the Continuing Disclosure Resolution. See APPENDIX H hereto.

The failure by the Agency to observe or perform any of its obligations under the Continuing Disclosure Resolution will not constitute an Event of Default under the Resolution. If the Agency fails to comply with any provision of the Continuing Disclosure Resolution, any Holder or "Beneficial Owner" of the Outstanding 2022 Series A and B Bonds will be entitled to take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause the Agency to comply with its obligations under the Continuing Disclosure Resolution. However, the Continuing Disclosure Resolution provides that no Holder or Beneficial Owner of the 2022 Series A and B Bonds will have the right to challenge the content or the adequacy of the information contained in any Annual Filing or any Event Notice by judicial proceedings unless the Holders or Beneficial Owners of the 2022 Series A and B Bonds representing at least 25% in aggregate principal amount of all 2022 Series A and B Bonds join in such proceedings.

As described under the caption "DESCRIPTION OF THE 2022 SERIES A AND B BONDS – Book-Entry Only System – *General*" herein, all of the 2022 Series A and B Bonds will be issued only in book-entry form through DTC. See the discussion under the same caption for a description of DTC's current procedures with respect to the enforcement of bondholders' rights.

During the past five years, the Agency has complied in all material respects with all of its obligations under each undertaking it has made pursuant to the provisions of paragraph (b)(5) of Rule 15c2-12.

Other

This Official Statement includes summaries of the terms of the 2022 Series A and B Bonds, the Resolution, certain provisions of the Act and other statutes, regulations, orders and opinions and certain contracts and other arrangements for the supply of power and energy and the raising of revenues for the payment of the 2022 Series A and B Bonds and the other indebtedness of the Agency. The summaries of and references to all documents, statutes, regulations, orders, opinions, 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, regulation, order, opinion, report or instrument.

In connection with the preparation of this Official Statement, the Agency has relied upon certain information relating to the Department and Anaheim furnished to the Agency by such Power Purchasers and upon certain information obtained from other sources. The information contained herein is subject to change without notice and the delivery of this Official Statement shall not, under any circumstances, create any implication that there has been no change in the affairs of the Agency, the Power Purchasers or any other person or entity discussed herein since the date hereof.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The information contained in this Official Statement contains "forward-looking statements" within the meaning of the federal securities laws. These forward-looking statements include, among others, statements concerning expectations, beliefs, opinions, future plans and strategies, anticipated events or trends and similar expressions concerning matters that are not historical facts. Examples of forward-looking statements include, among others, statements concerning purchases of energy by the Power Purchasers, sharing of costs by the Power Purchasers, potential effects of deregulation, potential effects of litigation, current and proposed environmental regulations and related estimated expenditures, access to sources of capital and anticipated uses of capital, the Agency's liquidity and financial condition, financing activities, estimated sales and purchases of power and energy, and estimated construction and other expenditures.

Forward-looking statements are included, among other places, in the sections of this Official Statement captioned "INTRODUCTORY STATEMENT," "RISK FACTORS," "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS," "ELECTRIC INDUSTRY RESTRUCTURING," "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY," "INTERMOUNTAIN POWER AGENCY," "THE AGENCY'S FINANCING PROGRAM," "FISCAL YEAR 2021-2022 ANNUAL BUDGET" and "LITIGATION."

The forward-looking statements contained in this Official Statement are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements. Accordingly, there can be no assurance that such indicated results will be realized. These risks include but are not limited to:

- changes in the rating of the Agency's bonds or the credit rating of the Agency, the Department, or a material Power Purchaser;
- the ability and willingness of counterparties of the Agency to make payments as and when due and to perform as required;
- default under any of the Power Sales Contracts or Renewal Power Sales Contracts;
- effects of compliance with changing environmental, safety, licensing, regulatory and legislative requirements in addition to those described herein;
- national, state and local laws, rules, referenda, propositions, initiatives or policies, including those directed at limiting or restricting emissions of carbon dioxide ("CO_2") and other greenhouse gases ("GHGs") or that favor "renewable" or "green" electric generation methods over generation facilities powered by fossil fuels, including the "Affordable Clean Energy" rule promulgated by the United States Environmental Protection Agency ("EPA");
- physical risks associated with climate change such as changes in weather conditions, changes in precipitation, extreme weather events, temperature and humidity, which could vary customers' energy needs, cause damage or increase operating costs, resulting in positive or

negative effects on the Agency's and the Power Purchasers' revenues and financial performance;

- substantial public sentiment against the use of coal as a fuel for electric generating facilities;
- unavailability of or substantial increases in the cost of fuel for the Project or the transportation of such fuel;
- a failure to obtain or maintain permits;
- effects resulting from future changes in national energy policy or the manner in which such policy is implemented;
- effects of deregulation;
- advances in technology available to and used in generation and distribution facilities including technology used by competitors and residential or commercial customers of the Power Purchasers;
- issues relating to the reliability of electric transmission systems and grids, such as the reliability issues highlighted or exposed by power blackouts that have occurred in widespread regions of North America at various times;
- operational, generation, and transmission failures;
- availability and sufficiency of transmission capacity, particularly during times of high demand;
- issues relating to the ability to issue tax-exempt obligations to finance or refinance electric generation or transmission facilities, 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;
- increases in costs and unavailability of capital;
- current and future litigation, regulatory investigations, proceedings, or inquiries;
- war, sanctions, embargos, pandemics, and other global economic and political events that impact generation development, commodity markets and energy supply and consumption;
- inadequate risk management procedures and practices;
- cybersecurity threats;
- seismic activity, wildfires or other natural or human-caused disasters;
- changes in load requirements;
- effects of inflation on the operating and maintenance costs of an electric utility and its facilities;
- investment performance of the Agency's invested funds;
- effects of possible manipulation of electric markets;
- the effect of accounting pronouncements issued periodically by standard-setting bodies;

- effects of changes in the economy; and
- other factors discussed in this Official Statement.

In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Prospective purchasers of the 2022 Series A and B Bonds should not place undue reliance on these forward-looking statements, which reflect management's views only as of the date hereof. The Agency does not undertake any obligation to correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

RISK FACTORS

The following discussion of certain risks that could affect payments to be made with respect to the 2022 Series A and B Bonds is not exhaustive, should be read in conjunction with all other parts of this Official Statement and should not be considered a complete description of all risks that could affect payments with respect to the 2022 Series A and B Bonds. Prospective purchasers of the 2022 Series A and B Bonds should analyze carefully the information contained in this Official Statement, including the Appendices hereto.

Drought

The Project is located in an arid portion of the intermountain west. The flows in the water system from which the Agency's water rights and water shares derive result from runoff of snowpack in the mountains. For 2022, flows in that water system are similar to the lowest level recorded since the mid-1950s. To date, the impact of the low flow conditions has been to reduce the amount of water available for lease to the agricultural users near the Intermountain Generating Station.

The Agency did plan the acquisition and maintenance of its water assets to permit continued operation of the Project to address such record low flows. The Agency cannot guarantee, however, that weather conditions will not worsen beyond such record levels to the point of impacting the operation of the Project. The Agency cannot predict the impact on its financial condition if drought conditions impact Project operations.

Wildfire

The Agency's transmission lines have been impacted on occasion by wildfires near the transmission rights-of-way. While the Project facilities are not located in forested areas, the brushland along the Agency's transmission rights-of-way have fueled significant wildfires. Such brush fires have not damaged the Agency's transmission lines, but have generated smoke and heat that have interfered with the operation of the transmission assets. In 2020, the smoke and heat of the Canal Fire caused transmission lines to go offline.

The Department does maintain an active team to patrol the Project's transmission systems, including by helicopter, to identify and repair damage to the Agency's transmission lines and identify potential wildfire hazards. The Agency also follows industry practices for maintaining its facilities to minimize wildfire risks. The Agency cannot guarantee, however, that Project facilities will not be impacted by a wildfire or be identified as the cause of such a fire. The Agency cannot predict the impact on its financial condition if a wildfire did damage Project facilities or if a wildfire were determined to have been caused by the Project facilities.

Cyber Security

Since the Project consists of critical infrastructure, it is considered to be at higher risk of cyberattack. The Project does have members of staff and contracts with consultants dedicated to protecting Project systems from cyberattack. The Agency follows the Department's policy and procedures for complying with NERC's Critical Infrastructure Protection ("CIP") standards with some modification to tailor such policies and procedures to the circumstances of the Project. The Project complies with NERC CIP standards that apply to the Project's facilities. The Project's computer networks are designed, maintained and updated on a regular basis to limit the potential for successful cyberattacks. The Agency also has maintained insurance at least at levels standard for projects similar to the Project. The Agency cannot guarantee, however, that cyberattacks will not succeed in disrupting the operation of the Project. The Agency cannot predict the potential impact of such an attack on the Agency or the extent to which the Agency's insurance may mitigate such impact. Accordingly, the Agency cannot predict the potential impact such an attack could have on the Agency's financial condition.

Credit Ratings

The 2022 Series A and B Bonds have been assigned the credit ratings set forth in "RATINGS" below. The ratings indicate the rating agencies' assessment of the Agency's ability to pay the principal of and interest on the 2022 Series A and B Bonds. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. There is no assurance that a particular rating will remain in effect for any given period of time or that it will not be revised, either downward or upward, or withdrawn entirely, if in the judgment of the rating agency that assigned such rating, circumstances so warrant. Any downward revision or withdrawal of any rating may have an adverse effect on the market price of the 2022 Series A and B Bonds.

Credit Risk

Credit risk with respect to the Agency's indebtedness is the risk that the Agency will not pay principal or interest when due. The Agency will rely on payments under the Power Sales Contracts and the Renewal Power Sales Contracts to fund the payments of principal of and interest due on the 2022 Series A and B Bonds.

The Agency's ability to make timely payments is subject to counterparty credit risk related to contractual obligations with various parties, including the Power Purchasers and the Agency's suppliers. Adverse economic conditions or other events affecting counterparties with whom the Agency conducts business could impair the ability of the Power Purchasers to pay for services. As the Monthly Power Costs paid by the Power Purchasers provide the funding for, among other things, the Agency's operational expenses and debt service, the Agency depends on the Power Purchasers to be able to make payments on the Agency's indebtedness on a timely basis.

The California Purchasers have contracted, pursuant to their Power Sales Contracts, to purchase 78.943% of the net capability of the Generation Station. Therefore, the failure of the California Purchasers generally, or of any one of them individually (particularly the Department), to remit payments on a timely basis may result in a significant adverse impact on the Agency's business, financial condition and results of operations.

In addition, all of the California Purchasers and most of the Utah Purchasers are municipalities. Any of these Power Purchasers may be authorized to initiate proceedings under Chapter 9 of the Federal Bankruptcy Code without prior notice to or consent of its creditors, which may enable it to reject its existing executory contracts, such as the Power Sales Contracts and the Renewal Power Sales Contracts, relieving the municipality of any further obligation to perform thereunder.

Furthermore, the Power Sales Contracts and the Renewal Power Sales Contracts provide that the obligations of the respective Power Purchasers are several and not joint. This provision and the requirement of Coordinating Committee or Renewal Contract Coordinating Committee, as applicable, approval for changes in the Agency's annual budget may limit the Agency's ability to make up shortfalls in revenues resulting from a Power Purchaser's default.

In addition, to the extent that the Agency is able to enforce provisions of the Power Sales Contracts or the Renewal Power Sales Contracts that permit the Agency to bill non-defaulting Power Purchasers for shortfalls in revenues (notwithstanding the several liability of the Power Purchasers), the increased billings to the non-defaulting Power Purchasers may exceed the financial capabilities of one or more of the non-defaulting Power Purchasers. In such a situation, there can be no guarantee that the increased billings would be paid in a timely fashion, or at all. To the extent the amount to be paid by the non-paying Power Purchaser is not offset by revenues received from other Power Purchasers or from sales of the non-paying Power Purchaser's entitlement to the output of the Project to third parties, the Agency may not be able to pay when due principal of or interest on the Agency's indebtedness (including the 2022 Series A and B Bonds).

Governmental Requirements

Electric utilities are subject to extensive governmental requirements with respect to the operation, maintenance and improvement of facilities, including regulations governing safety and security, air and water quality, land use, hazardous and solid waste, and other environmental factors and the potential health effects from electric and magnetic fields associated with power lines and related sources. The coal-fired electrical generating industry also is experiencing increased scrutiny by some sectors of the public regarding climate change. Federal, state and local requirements are subject to changes arising from legislative, executive and judicial action. Consequently, although the Agency believes that the Project currently complies with all applicable governmental requirements, there can be no assurance that the Project will remain subject to the requirements currently in effect or in compliance with future requirements, or will be able to continue to satisfy existing requirements. Evolving requirements could result in additional capital or operating expenditures, reduced operating levels or the complete shutdown of individual electric generating units ("EGUs").

The Agency cannot predict what impact climate change regulation, environmental regulations and concerns regarding electric and magnetic fields might have on the business, operations and financial condition of the Agency, the Project or the Power Purchasers, but their influence could be significant. See "ELECTRIC INDUSTRY RESTRUCTURING" and "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" below.

Permits

Among the various governmental requirements applicable to the Agency, the Agency must comply with the requirements of licenses and permits from various regulatory authorities and abide by their respective orders. Although the Agency believes that it has obtained all licenses and permits necessary for the ownership and operation of the Project, the licenses and permits impose continuing obligations on the Agency. Should the Agency or the Department (as Operating Agent under the terms of the Construction Management and Operating Agreement, as defined in the Resolution) be unsuccessful in maintaining current necessary licenses or permits (or obtaining additional licenses or permits that may become necessary) or should regulatory authorities with jurisdiction over the Project initiate any investigations or enforcement actions, revoke any necessary licenses or permits or impose penalties on the Agency, the Project or the Department, or issue orders to the Agency, the Project or the Department to cease or modify operations, the business, financial condition and results of operations of the Agency or the Power Purchasers could be adversely affected. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – *Section 114 Information Requests*" below.

Moreover, the Agency has agreed to indemnify the Department from all liability and expense on account of any and all damages, claims or actions including injury to or death of persons or damage to property arising from any act or failure to act (including a failure to obtain or maintain a required permit), except for the Department's acts of intentional wrongdoing or acts of gross negligence. This agreement could limit the Agency's ability to replace reserves or revenues that may be lost as a result of action by regulatory authorities.

Operating Uncertainties

The Agency's business, including the operation of the Agency's electric generation and transmission systems, involves many risks, including breakdown or failure of expensive and sophisticated equipment; potential design flaws; wear and tear from operating the generating units at the Project at varying levels of production (including cycling of generation to accommodate peak demand); processes and personnel performance; operating limitations that may be imposed by equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; and catastrophic events such as fires, including wildfires, explosions, earthquakes, drought, severe weather, pandemic health events, or other similar occurrences.

In addition, the Agency's information technology systems and network infrastructure may be vulnerable to internal or external cyberattack, unauthorized access, computer viruses or other attempts to harm the Agency's systems or misuse the Agency's confidential information. Cybersecurity threats are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage the Agency's reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The catastrophic events that could potentially have an adverse impact on the Project's operation include earthquakes. Some, if not all, of the Project exists in areas subject to seismic activity. Although the Agency maintains some earthquake insurance, no assurance can be given that a future seismic event will not materially adversely affect the operation of the Project or the Agency's financial condition.

The Agency has implemented training and preventive maintenance programs and has security systems and related protective infrastructure in place, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of the Agency's generation or transmission facilities or related business processes. In those cases, the Power Purchasers may need either to produce replacement power from their other facilities or to purchase power from other suppliers at potentially volatile and higher cost in order to serve their loads. There is no guarantee that such replacement power would be available.

These and other operating events may increase the cost of Project power and energy and may materially affect the business, financial condition and results of operations of the Agency and the Power Purchasers.

Dangers and Risks Involved in Generation and Transmission of Electricity

Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical equipment. Injuries caused by such contact can subject the Agency to liability that, despite the existence of insurance coverage, can be significant. In light of the potential impact of natural disasters, which can cause damage to facilities and outages, the Agency's focus includes public

safety issues. Penalties and liabilities for failure to sufficiently address public safety issues could be significant but are very difficult to predict.

Legal Proceedings

The Agency is occasionally subject to suits related to its business. Such litigation has included claims for very sizeable damages, including punitive damages, and injunctive relief.

While the Agency intends to defend itself in litigation that may be brought against the Agency, litigation is subject to many uncertainties, and the Agency cannot predict the outcome of individual matters. It is possible that the final resolution of some of the matters in which the Agency is involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could be material. Similarly, it is also possible that the terms of resolution could require that the Agency change business practices and procedures. Further, litigation could result in the imposition of financial penalties or injunctions which could limit the Agency's ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct the Agency's business, including the siting or permitting of facilities. Any of these outcomes could adversely affect the Agency's business, financial condition and results of operations, including operation of the Project. See "LITIGATION" below.

COVID-19 Pandemic

The COVID-19 pandemic that has affected the United States and the world since early 2020 has led to efforts to maintain a social distance among individuals in order to reduce the spread of the virus. The pandemic has caused the disruption of daily life across the country. Restrictions on movement may be expanded as the crisis continues.

In light of the pandemic, Intermountain Power Service Corporation ("IPSC"), the employer of the personnel that operate the Project, has implemented procedures to limit the employees on site to essential personnel, quarantine employees who have been exposed to the virus causing COVID-19, defer Project maintenance and repairs where possible to limit contact with outside contractors and encourage safe work practices to minimize the risk of spreading COVID-19 among IPSC's workforce. Although IPSC's response to the COVID-19 pandemic has not had significant impacts on operations of the Project, the continuation of the COVID-19 pandemic continues to create uncertainty around the potential impact on the Project. These impacts may include significant loss of productivity among IPSC personnel or the inability to complete maintenance and repairs in a timely manner as a result of unavailability of equipment, materials or personnel among the Project's vendors.

Furthermore, the COVID-19 pandemic has impacted municipal bond and other financial markets. In the early days of the pandemic, the municipal bond market suffered a significant decrease in liquidity. While the municipal bond market appears to have largely recovered from the prior liquidity issues, the failure of a resolution to the COVID-19 pandemic may have impact on financing of large infrastructure projects. This may impact the ability of the Agency or the Power Purchasers to access capital markets to address their own liquidity needs.

The Power Purchasers have identified risks to their operations and financial condition related to the COVID-19 pandemic. Those risks include impairment of the ability to generate revenues from the operation of their utilities. That may result in a reduction in funds available for Power Purchasers to pay amounts due to the Agency under the Power Sales Contracts. Since the inception of the COVID-19 pandemic, the Power Purchasers have not missed any payments nor made any late payments under the Power Sales Contracts.

The Agency cannot predict (i) the duration or extent of the COVID-19 outbreak; (ii) to what extent the COVID-19 outbreak may affect the operations and revenues of the Project; (iii) to what extent COVID-

19 may disrupt the economic factors that impact the Project, manufacturing or supply chain, or whether any such disruption may adversely impact Project-related construction, the cost, sources of funds, schedule or implementation of the Project's capital improvement program, or other Project operations; (iv) to what extent the Agency may be asked to provide deferrals, forbearances, adjustments or other changes to Power Purchasers; or (v) whether any of the foregoing may have a material adverse effect on the finances and operations of the Agency, the Project or the Power Purchasers. Prospective investors should consider that the restrictions and limitations instituted related to COVID-19 may increase (even after they are decreased), and upheaval to the national and global economies may continue and/or be exacerbated, at least over the near term, and the recovery may be prolonged, and therefore, COVID-19 may adversely impact Project revenues.

Disruptions in the Financial Markets

Certain market disruptions could constrain, at least temporarily, the Agency's ability to maintain sufficient liquidity and to access capital on favorable terms or at all. These disruptions include: (a) market conditions generally; (b) an economic downturn or recession; (c) a pandemic such as COVID-19; (d) instability or uncertainty in the financial markets; (e) a tightening of lending and lending standards by banks and other credit providers; (f) the overall health of the energy industry; (g) negative events in the energy industry, such as a bankruptcy of an unrelated energy company; (h) war or threat of war; or (i) cyber or terrorist attacks or threatened attacks on the Agency's facilities or the facilities of unrelated energy companies. If the Agency is unable to access the financial and credit markets to meet liquidity and capital expenditure needs, it may adversely affect the Agency's liquidity, credit ratings, financial condition and the timing and amount of the Agency's capital expenditures. Furthermore, such disruptions may impair the Power Purchasers' ability to make timely payments to the Agency, impair their financial condition, or negatively impact their credit ratings, which in turn could impair the Agency's financial condition and credit ratings.

Construction of the Repowering Project and Hydrogen Facilities

The construction of large, complex generating units involves significant financial risk. The Agency relies on the Department as its Project Manager and third party contractors for the oversight of the construction of the Repowering Project and does not exercise direct control over the construction process. The Power Purchasers are responsible for construction costs based on their cost shares. Factors that could lead to further cost increases and schedule delays or even the inability to complete the Repowering Project include:

- performance by the Department and the third-party contractors in management of construction processes and costs;
- Subcontractor and supplier performance, including compliance with the design specifications approved and quality standards set forth by applicable regulatory bodies;
- shortages, increased costs or inconsistent quality of labor, equipment and materials;
- changes in labor costs, availability and productivity;
- performance by manufacturers and contractors under long-term service and maintenance contracts;
- loss of access to intellectual property rights necessary to construct or operate the Repowering Project;

- increases in the Agency's cost of debt financing as a result of changes in market interest rates or as a result of construction schedule delays;
- engineering or design problems;
- delays in construction, testing and start-up activities;
- operational readiness;
- erosion of public and policymaker support;
- contract disputes;
- permits, approvals and other regulatory matters;
- changes in project design or scope;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- adverse weather conditions; and
- work stoppages.

The ultimate outcome of these matters cannot be determined at this time; however, these risks could continue to impact the in-service dates and cost of the Generation Renewal Project which would increase the cost of electric service the Agency provides to the Power Purchasers and, as a result, could affect their ability to perform their contractual obligations to the Agency.

PLAN OF FINANCING

Purpose of Issue

The Agency is issuing the 2022 Series A and B Bonds in order to (i) finance or refinance a portion of the Cost of Acquisition and Construction of the Gas Repowering, (ii) provide the moneys required to refund the Refunded Subordinated Bonds, (iii) provide moneys sufficient to pay capitalized interest on the 2022 Series A and B Bonds through July 1, 2025, (iv) provide moneys for deposit to the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established under the Resolution, and (v) pay the costs of issuance of the 2022 Series A and B Bonds.

All of the Bonds previously issued under the Resolution heretofore have been paid at maturity, redeemed or deemed to have been paid within the meaning and effect of the Resolution. As a result, upon the issuance of the 2022 Series A and B Bonds, the 2022 Series A and B Bonds will be the only Bonds Outstanding under (and as defined in) the Resolution.

Estimated Cost and Schedule of Generation Renewal Project

The Cost of Acquisition and Construction of the Gas Repowering, including the portion of such costs shared between the Gas Repowering and the STS Renewal Project, are, as of March 3, 2022, projected to be approximately $1,700,000,000. Such estimate includes costs incurred to date of approximately $100,000,000 which are being refinanced with a portion of the proceeds of the 2022 Series A and B Bonds. (See "INTRODUCTORY STATEMENT – General" herein.) The balance of such estimated costs is anticipated

to be funded in part through the balance of the proceeds of the 2022 Series A and B Bonds and the Agency's future bond issuances.

The Agency has contracted with The Industrial Company, a Kiewit company ("TIC") to engineer, procure and construct the Generation Renewal Project. The contractor is experienced in the design and construction of power generating facilities of the type contemplated by the Generation Renewal Project. The date-certain, firm price engineering, procurement and construction contract ("EPC Contract") was signed by the Agency and TIC on March 18, 2022. The EPC Contract covers the complete scope of the Generation Renewal Project, with the exception of the procurement of the Mitsubishi M501JAC combustion turbines which have been procured pursuant to a contract with the manufacturer.

The schedule and performance guarantees under the EPC Contract include liquidated damages for performance, liquidated damages for delay, retentions, a letter of credit and a parent guarantee for 100% of the contract price. The EPC Contract includes output, heat rate and reliability guarantees.

The following describes significant construction milestones for the Generation Renewal Project and the STS Renewal Project:

Approximate Construction Schedule

Milestone Activity	Date – Scheduled (S) or Actual (A)
Gas Transportation Contract Award	November 2019 (A)
Gas Turbine-Generator Contract Award	February 2020 (A)
Site Preparation Commencement	October 2021 (A)
Generation EPC Contract Award	March 2022 (A)
STS Renewal Project Contracts Award	October 2022 (S)
Natural Gas Available	May 2024 (S)
Gas Repowering Commercial Operation Date	June 2025 (S)
STS Renewal Project Substantially Complete	April 2026 (S)

The Power Sales Contracts provide that the Gas Repowering is to be in commercial operation by July 1, 2025. As of the date of this Official Statement, the engineering and design of the Gas Repowering are still in preliminary stages. Although substantial completion of the STS Renewal Project is expected to occur after the commercial operation date of the Generation Renewal Project, the Agency expects that the elements of the STS Renewal Project that are necessary for the operation of the Project, as modified by the Generation Renewal Project, will be in place by the commercial operation date of the Generation Renewal Project. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" herein.) The contracts for the Hydrogen Conversion and Storage Capacity provide that the related facilities are to be substantially complete by October 1, 2024, providing the capacity to convert water into hydrogen using renewable energy and to store such hydrogen during the testing phase of the Gas Repowering in anticipation of the commercial operation date of the Gas Repowering.

The combustion turbines are advanced class units that offer fast ramp and low heat rate and will have the capability of producing energy with a mix of natural gas and green hydrogen (30% hydrogen by volume). The Agency anticipates a substantial reduction in greenhouse gas emissions when the new combustion turbines achieve commercial operation and become the sole source of generation for the Project. The reduced nameplate capacity of the units will allow the Southern Transmission System to integrate additional renewable energy for the California Purchasers.

The Hydrogen Betterments include upgrades to the natural gas units to facilitate the increase of such units' capability to use a fuel mix with green hydrogen in excess of 30%, with a goal of reaching 100% of green hydrogen fueled operation by 2045. Such Hydrogen Betterments are intended to reduce the cost of

increasing such capability if and when the determination is made to increase the hydrogen component of fuel used at the Project. The increase in such capability will not be undertaken prior to June 16, 2027.

RBC Drawdown Bond Facility

The Agency's Subordinated Power Supply Revenue Bonds, 2019 Drawdown Series (the "2019 Series Drawdown Bonds") previously were authorized to be issued in an amount at any time outstanding not to exceed $100,000,000 pursuant to a resolution adopted by the Agency on December 27, 2019 entitled "Tenth Supplemental Subordinated Power Supply Revenue Bond Resolution" (the "Tenth Supplemental Subordinated Resolution"), to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering. In connection with such authorization, the Agency entered into (a) a Bond Purchase Agreement (the "RBCCM BPA"), dated December 27, 2019, by and between the Agency and RBC Capital Markets, LLC ("RBCCM") and (b) the Bondholder's Agreement (the "RBC Bondholder's Agreement" and, together with the RBCCM BPA, the "RBC Agreements"), dated as of December 1, 2019, between the Agency and Royal Bank of Canada ("RBC"). RBC is the parent company of the RBCCM, an Underwriter of the 2022 Series A and B Bonds.

The Agency, RBCCM and RBC expect to amend and restate the Tenth Supplemental Subordinated Resolution, the RBCCM BPA and the RBC Bondholder's Agreement (collectively, the "RBC Drawdown Facility") in late- April or early- May 2022 in order, among other things, to increase the amount authorized to be outstanding at any time thereunder from $100,000,000 to $200,000,000 and to extend the latest date by which drawings may be made thereunder from December 31, 2022 to December 31, 2023. The RBC Drawdown Facility is a revolving credit facility, under which funds may be borrowed, repaid and reborrowed.

Proceeds from the issuance of the 2022 Series A and B Bonds are expected to refund $100,000,000 of the outstanding amounts of the 2019 Series Drawdown Bonds. It is anticipated that, after the date of issuance of the 2022 Series A and B Bonds, the Agency will continue to make drawings under the RBC Drawdown Facility in order to advance funds to be used for the acquisition and construction of the STS Renewal Project. All such drawings are expected to be repaid to the Agency, and applied to the payment of amounts outstanding under the RBC Drawdown Facility, from the proceeds of bonds or other obligations of SCPPA to be issued for such purpose. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" herein.)

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ESTIMATED SOURCES AND USES OF FUNDS

The sources and uses of funds in connection with the issuance of the 2022 Series A and B Bonds are estimated to be as follows:

	2022 Series A	2022 Series B
Sources:		
Principal Amount	$732,755,000.00	$64,850,000.00
Plus: Original Issue Premium	88,695,101.10	620,030.70
Total Sources	$821,450,101.10	$65,470,030.70
Uses:		
Construction Fund Deposit	$554,498,376.89	$42,378,239.78
Refunding of Refunded Subordinated Bonds (1)	92,000,000.00	8,000,000.00
Deposit to Debt Service Account in Debt Service Fund for payment of Capitalized Interest on the 2022 Series A and B Bonds (2)	113,761,803.33	9,637,733.15
Deposit to Initial Subaccount in Debt Service Reserve Account in Debt Service Fund (3)	58,019,105.77	5,134,784.49
Agency's Costs of Issuance (including Underwriters' Discount) (4)	3,170,815.11	319,273.28
Total Uses	$821,450,101.10	$65,470,030.70

(1) Reflects a refunding of $100,000,000 of the outstanding amounts of the 2019 Series Drawdown Bonds.

(2) Such amount will pay all interest payable on the 2022 Series A and B Bonds through July 1, 2025.

(3) Upon such deposit, amount on deposit in Initial Subaccount will be equal to the Debt Service Reserve Requirement therefor.

(4) Includes legal, advisory, bond rating and printing fees and other costs of issuance.

SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS

Pledge Effected by the Resolution

The Resolution provides that the Bonds, including, without limitation, the 2022 Series A and B Bonds, shall be direct and special obligations of the Agency payable solely from and secured solely by the Trust Estate, which is defined to mean (i) the proceeds of the sale of the Bonds, (ii) the Revenues, and (iii) all Funds and Accounts established by the Resolution (other than (X) the Debt Service Reserve Account in the Debt Service Fund, (Y) any Decommissioning Fund which may be established pursuant to the Resolution and (Z) the STS Capital Improvement Construction Fund), including the investments and investment income, if any, thereof, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth therein.

"Revenues" is defined in the Resolution to mean (a) all revenues, income, rents and receipts derived or to be derived by the Agency from or attributable to the ownership and operation of the Project, including all revenues attributable to the Project or to the payment of the costs thereof received or to be received by the Agency under the Power Sales Contracts and the Renewal Power Sales Contracts or under any other contract for the sale of power, energy, transmission or other service from the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services, output or capacity thereof, (b) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, and (c) interest received or to be received on any moneys or securities (other than in the Construction Fund or the STS Capital Improvement Construction Fund) held pursuant to the Resolution and required to be credited to the Revenue Fund.

Principal of and interest on the 2022 Series A and B Bonds rank on a parity with each other and with each other Series of Bonds which the Agency may issue hereafter. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Additional Bonds" herein.

The Bonds will not be obligations of the State of Utah or any political subdivision thereof, other than the Agency, or any member of the Agency, any Power Purchaser or the Project Manager or Operating Agent and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both will be pledged for the payment of Bonds. No holder of Bonds or receiver or trustee in connection with the payment of Bonds will have the right to compel the State of Utah, any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both to exercise its appropriation or taxing powers. The Agency has no taxing power.

For a further discussion of the security and sources of payment for the 2022 Series A and B Bonds, see "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Pledges Effected by the Resolution" and "– Nature of Obligation" in APPENDIX A hereto.

Flow of Funds

The Resolution establishes the following Funds for the application of Revenues while Bonds are Outstanding:

Fund	**Held By**
Revenue Fund	Agency
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Indebtedness Fund	Trustee
Subordinated Indebtedness Debt Service Account	
Such other accounts as may be established by the Agency in such Fund	
Self-Insurance Fund	Agency

Pursuant to the Resolution, all Revenues received are to be deposited promptly in the Revenue Fund. Each month, amounts in the Revenue Fund are to be used to pay Operating Expenses for such month. After such payment (or provision for payment) of Operating Expenses, monthly payments in the amounts indicated below are to be made from the Revenue Fund to the following Funds and Accounts in the following order of priority:

1. To the Debt Service Account and to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such Account and subaccounts (excluding, in the case of the Debt Service Account, the amount set aside from the proceeds of Bonds or other evidences of indebtedness of the Agency for payment of interest on Bonds in excess of the amount thereof to be applied to pay interest accrued and unpaid and to accrue on Bonds to the last day of the then current calendar month) equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement related thereto, respectively. The Trustee will apply amounts in the Debt Service Account to the payment of principal or sinking fund redemption price of and interest on Bonds when due.

2. To the Subordinated Indebtedness Debt Service Account in the Subordinated Indebtedness Fund and each other account within the Subordinated Indebtedness Fund, such amounts as shall be required to be deposited thereto so that the balance therein or the amount

deposited thereto, as the case may be, shall equal the amount required to be on deposit therein as of the end of such month or the amount required to be deposited thereto during such month, as applicable, determined as provided in the respective resolutions, indentures or other instruments, including any Supplemental Resolution, relating to such account or the Subordinated Indebtedness (as defined in the Resolution) payable therefrom or secured thereby. The Trustee will apply amounts in the Subordinated Indebtedness Debt Service Account and such other accounts to the purposes specified with respect thereto in the respective resolutions, indentures or other instruments, including any Supplemental Resolution, applicable thereto.

3. To the Self-Insurance Fund, one-twelfth of the total amount provided for such purpose in the then current Annual Budget, *provided, however*, that if a deficiency in said Fund is to be restored over a period which extends beyond the fiscal year during which such restoration shall have commenced pursuant to the provisions of the Resolution, then the deposits in each month to said Fund during such subsequent fiscal year shall be in the amount determined pursuant to the Resolution.

Funds paid by SCPPA to the Agency for deposit into the STS Capital Improvement Fund and funds paid by the Power Purchasers to the Agency for deposit into any Decommissioning Fund will be deposited directly into those funds. Funds held in any Decommissioning Fund will not be part of the Trust Estate. For a more detailed discussion of the application of monies deposited in the various funds and accounts, see "Application of Revenues" in APPENDIX A hereto.

Initial Subaccount in Debt Service Reserve Account

Pursuant to the Sixty-First Supplemental Resolution, the Agency has established a subaccount in the Debt Service Reserve Account in the Debt Service Fund known as the "Initial Subaccount," which Subaccount is for the benefit and security of all Holders of the Bonds of each Additionally Secured Series secured thereby. The term "Additionally Secured Series" is defined in the Sixty-First Supplemental Resolution to mean (a) the 2022 Series A and B Bonds and (b) any Series of Bonds issued after the date of adoption of the Sixty-First Supplemental Resolution for which the Supplemental Resolution authorizing the Bonds of such Series shall provide that the payment of the principal or sinking fund Redemption Price, if any, of, and interest on, the Bonds of such Series shall be secured, in addition to the pledge and assignment created pursuant to the Resolution in favor of all of the Bonds, by a pledge and assignment of amounts on deposit in the Initial Subaccount; *provided, however*, that no Variable Interest Rate Bonds shall be additionally secured by amounts on deposit in the Initial Subaccount; and *provided, further*, that if any Series of Bonds is to be an Additionally Secured Series, then it will be a condition to the issuance of the Bonds of such Series that the amount on deposit in the Initial Subaccount after giving effect to the issuance of the Bonds of such Series is equal to the Initial Subaccount Debt Service Reserve Requirement (hereinafter defined).

Pursuant to the Sixty-First Supplemental Resolution, the amounts on deposit in the Initial Subaccount as may from time to time be available therefor (including the investments held as a part of such Subaccount) are pledged and assigned to the Holders of the Bonds of each Additionally Secured Series secured thereby, including the 2022 Series A and B Bonds, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

Amounts in the Initial Subaccount are to be applied to make payment of the principal or sinking fund redemption price of, or interest on, the Bonds of each Additionally Secured Series secured thereby (including the 2022 Series A and B Bonds) when due in the event that amounts on deposit in the Debt Service Account in the Debt Service Fund are not sufficient therefor, ratably, based on the deficiency that exists with respect to each Additionally Secured Series secured thereby.

Pursuant to the Sixty-First Supplemental Resolution, the Agency is required to deposit and maintain, or cause to be deposited and maintained, in the Initial Subaccount moneys and Investment Securities in an amount equal to the Initial Subaccount Debt Service Reserve Requirement. The term "Initial Subaccount Debt Service Reserve Requirement" is defined in the Sixty-First Supplemental Resolution to mean, as of any date of calculation, an amount equal to the greatest amount of Aggregate Debt Service (as defined in the Resolution) on all Bonds of each Additionally Secured Series secured by the Initial Subaccount for the then current or any future Fiscal Year. (See "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Definitions" in APPENDIX A hereto for the definition of Aggregate Debt Service.) Upon the issuance of the 2022 Series A and B Bonds, the Initial Subaccount Debt Service Reserve Requirement will be funded from a portion of the proceeds of the 2022 Series A and B Bonds.

Whenever the amount on deposit in the Initial Subaccount exceeds the Initial Subaccount Debt Service Reserve Requirement, such excess will be deposited in the Revenue Fund established pursuant to the Resolution and applied to the purposes to which other amounts in the Revenue Fund are required to be applied (see "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Application of Revenues" in APPENDIX A hereto); *provided, however*, that unless otherwise approved by the Agency and by the Coordinating Committee, such excess must be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness.

In the event of the refunding or defeasance of any Bonds of an Additionally Secured Series secured by the Initial Subaccount, the Trustee will, upon the direction of an authorized officer of the Agency, withdraw from the Initial Subaccount all or any portion of the amounts accumulated therein and transfer the amount so withdrawn to itself, as such Trustee, to be held for the payment of the principal or redemption price, if applicable, and interest on such Bonds being refunded or defeased; *provided, however*, that such withdrawal will not be made unless (i) immediately thereafter, the Bonds being refunded or defeased shall be deemed to have been paid within the meaning of the Resolution and (ii) the amount remaining in the Initial Subaccount, after giving effect to the issuance of any Bonds being issued to refund any Bonds being refunded and the disposition of the proceeds thereof, shall not be less than the Initial Subaccount Debt Service Reserve Requirement.

Construction Fund

The Resolution establishes a Construction Fund, to be held by the Agency, into which will be paid amounts required by the provisions of the Resolution and any Supplemental Resolution and, at the option of the Agency, any moneys received for or in connection with the Project by the Agency, unless required to be otherwise applied as provided in the Resolution. In addition, proceeds of insurance for physical loss or damage to the Project, including proceeds of any self-insurance fund, or of contractors' performance bonds pertaining to the period of construction of the Project will be paid into the Construction Fund. Within the Construction Fund, a separate account will be established for any Capital Improvements, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The Agency will pay from the Construction Fund the Cost of Acquisition and Construction of each Capital Improvement, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The completion of construction of any Capital Improvements shall be evidenced by a certificate or certificates of an Authorized Officer, filed with the records of the Agency, stating (i) that such Capital Improvements have been completed in accordance with the plans and specifications applicable thereto and in accordance with the Construction Management and Operating Agreement, (ii) the date of such completion, and (iii) the amount, if any, required in the opinion of the signer or signers for the payment of any remaining part of the Cost of Acquisition and Construction thereof. Upon the filing of such certificate, the balance in the separate account in the Construction Fund established therefor in excess of the amount,

if any, stated in such certificate shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts. If subsequent to the filing of such certificate it shall be determined that any amounts specified in such certificate as being required for the payment of any remaining part of the Cost of Acquisition and Construction are no longer so required, such fact shall be evidenced by a certificate or certificates of an Authorized Officer filed with the records of the Agency stating such fact and any amount shown therein as no longer being required shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts.

STS Capital Improvement Construction Fund

The Resolution establishes an STS Capital Improvement Construction Fund, to be held by the Agency, into which will be paid all payments-in-aid of construction received by the Agency from SCPPA in respect of the STS Renewal Project and certain other Capital Improvements to the Southern Transmission System that SCPPA determines shall be financed by SCPPA. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" herein.) Amounts in the STS Capital Improvement Construction Fund shall be applied to the Cost of Acquisition and Construction of the STS Renewal Project or such other Southern Transmission System Capital Improvements.

The STS Capital Improvement Construction Fund shall not be a part of the Trust Estate and, therefore, is not pledged to the payment of the Bonds.

Decommissioning Funds

At such time as the Agency shall determine, there may be established by Supplemental Resolution one or more Decommissioning Funds to provide for costs of decommissioning, retirement or disposal of facilities of the Project. Each Decommissioning Fund shall be held by the Agency. The amounts to be credited to any such Fund, and the purposes to which amounts in any such Fund are to be applied, shall be set forth in the Supplemental Resolution establishing such Fund.

Each Decommissioning Fund shall not be a part of the Trust Estate and, therefore, is not pledged to the payment of the Bonds.

Agency Rate Covenant

The Agency has represented in the Resolution that it has, and will have as long as any Bonds are Outstanding, good right and lawful power to establish and collect rates and charges with respect to the Project, subject only to the terms of the Power Sales Contracts, the Renewal Power Sales Contracts, the Construction Management and Operating Agreement and other related contracts. Pursuant to the Resolution, the Agency

has covenanted at all times to establish and collect rates and charges with respect to the Project to provide Revenues at least sufficient, together with other available funds, for the payment in each fiscal year of the sum of: (i) Operating Expenses, (ii) Aggregate Debt Service with respect to Bonds, (iii) the amount, if any, to be paid into each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund established under the Resolution, (iv) the amount to be paid into each separate account in the Subordinated Indebtedness Fund, and all other amounts payable in respect of, Subordinated Indebtedness, (v) the amount, if any, to be paid into the Self-Insurance Fund established under the Resolution and (vi) all other charges or liens payable out of Revenues.

Additional Bonds

The Agency reserves the right under the Resolution to issue additional Bonds for purposes of the Project and on the terms and conditions specified in the Resolution, which will rank equally and be on a parity, as to security and source of payment, with all other Bonds (including the 2022 Series A and B Bonds). See "Additional Bonds" in APPENDIX A hereto.

Power Sales Contracts

General. Under the Power Sales Contracts, the Power Purchasers are entitled to Project (as defined in the Power Sales Contracts) generation and transmission capabilities based on their respective Generation Entitlement Shares (as defined in the Power Sales Contracts) and transmission entitlements and are obligated to make payments therefor.

Each Power Sales Contract between the Agency and a Power Purchaser constitutes an obligation of the parties until the terms of all of the Power Sales Contracts expire on June 15, 2027. As long as any Bonds or Subordinated Indebtedness is outstanding or until provision has been made for the payment of all outstanding Bonds and Subordinated Indebtedness, the 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 that are pledged as security for Bonds and Subordinated Indebtedness or which will impair or adversely affect the rights of the holders of Bonds or Subordinated Indebtedness. The Agency has caused all such Bonds and Subordinated Indebtedness to have been legally defeased such that, based on the Agency's interpretation of the effect of Transition Project Indebtedness on such expiration, no indebtedness of the Agency will preclude the expiration of the Power Sales Contracts on June 15, 2027.

The Agency does not interpret the foregoing restrictions on termination and amendment of the Power Sales Contracts to cause the Power Sales Contracts to be extended beyond the stated termination date in the Power Sales Contracts, notwithstanding the existence of Bonds or Subordinated Indebtedness constituting Transition Project Indebtedness (as defined below) on such date. In connection with the authorization of the issuance of the 2019 Series Drawdown Subordinated Bonds (which are stated to mature on December 29, 2027), the Agency amended the Resolution to express that intention. "Transition Project Indebtedness" is defined in the Power Sales Contracts to mean Bonds (as defined in the Power Sales Contracts) or other obligations issued by the Agency prior to June 16, 2027 that by their terms shall be scheduled to remain outstanding after June 16, 2027.

Payments are to be made by the Power Purchasers on a "take-or-pay" basis; that is, whether or not the Project or any part thereof has been completed, is operating or 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 Power Sales Contracts constitute operating expenses of the respective California Purchasers and Utah Municipal Purchasers payable solely from their electric revenue funds, and general obligations of the respective Cooperative Purchasers.

Each Power Purchaser that is a municipally-owned electric system has covenanted in its Power Sales 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 to the Agency all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues. See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS – Nature of Obligation" in APPENDIX B hereto.

The Power Sales Contracts provide that the obligations of the respective Power Purchasers are several and not joint. A failure by a Power Purchaser to make payments when due under its Power Sales Contract may result in larger payments being made by the other Power Purchasers in subsequent periods for the purpose of enabling the Agency to pay operating expenses, debt service and other costs of the Project and to maintain required reserves therefor. To the extent the amount to be paid by the non-paying Power Purchaser is not offset by revenues from sales of power or transmission service derived by the Agency in respect of such non-paying Power Purchaser's Generation Entitlement Share or transmission entitlement, such non-payment may result in deficits in funds and accounts established under the Resolution. In such event, the Agency would be required to amend, in accordance with the Power Sales Contracts and the Resolution, the Annual Budget (as defined in the Power Sales Contracts) to provide increases in subsequent billings to all Power Purchasers, including the non-paying Power Purchaser, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Power Purchaser's Generation Entitlement Share or transmission entitlement to the other Power Purchasers. Amounts thereafter collected from such non-paying Power Purchaser are to be credited against the next billings of such other Power Purchasers as appropriate. In the event, however, of a termination of the Project and a resultant default by the Agency under the Resolution, each Power Purchaser would, under its Power Sales Contract, be severally obligated to pay only its respective Generation Cost Share (as defined in the Power Sales Contracts) and Transmission Cost Share (as defined in the Power Sales Contracts), if any, of the debt service on Bonds and on Subordinated Indebtedness, as well as other fixed costs.

In the event of a default or inability to perform by a Power Purchaser under its Power Sales Contract, the Agency may proceed to enforce the Power Purchaser's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or in equity. The Power Sales Contracts also provide that if a payment due under the Power Sales Contracts remains unpaid when due, the Agency may, upon 120 days' written notice to the Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities, the discontinuance by the Agency of delivery of capacity and energy to and the use of the Project facilities by a defaulting Power Purchaser will not reduce the obligation of such Power Purchaser to make payments under its Power Sales Contract. For information regarding certain acts adopted by the California Legislature in recent years that may limit the Agency's ability to sell or otherwise transfer a defaulting Power Purchaser's Generation Entitlement Share or electric energy attributable thereto to California investor-owned or publicly owned electric utilities to recover lost revenues resulting from such default, see "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gas Initiatives – *Federal*" and "– *California*" below.

See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" in APPENDIX B hereto.

Monthly Power Costs. During each Power Supply Year (as defined in the Power Sales Contracts), each Power Purchaser is obligated to pay its share of Monthly Power Costs, which consist, generally, of all of the Agency's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Project, to the extent not paid from the proceeds of Bonds and Subordinated Indebtedness or from notes or other evidences of indebtedness issued in anticipation thereof. Such costs,

which consist of a minimum cost component and a variable cost component, are billed monthly. Power Supply Years coincide with the Agency's fiscal years, which end at 12:01 a.m. on July 1.

The minimum cost component is billed each month for the then current month based on the estimates contained in the Annual Budget prepared by the Agency prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each month, the minimum cost component includes:

(i) the amounts which the Resolution requires the Agency to pay or deposit during such month into funds or accounts for debt service on, and reserve requirements for, Bonds and Subordinated Indebtedness;

(ii) one-twelfth of the amount which the Agency is required under the Resolution to pay or deposit during the Power Supply Year which includes such month into any other fund or account established by the Resolution, including any amount needed to eliminate a deficiency in any fund established under the Resolution whether or not resulting from a default in payments by any Power Purchaser of amounts due under any Power Sales Contract;

(iii) one-twelfth of the costs of producing and delivering capacity and energy from the Project during the Power Supply Year which includes such month, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of fuel for the Project; and

(iv) one-twelfth of the amount necessary during the Power Supply Year which includes such month to pay or provide reserves for payment of amounts required to be paid pursuant to the Act to counties, municipalities and school districts affected by the Project, Payments in Lieu of Ad Valorem Taxes (as defined in the Power Sales Contracts) and all other taxes which the Agency is required to pay.

The variable cost component is billed each month for the immediately preceding month. The variable cost component of Monthly Power Costs consists of all costs of fuel not included in the minimum cost component and is to be billed based on the cost of fuel utilized during such month.

If there is any revision of the Annual Budget after the commencement of any Power Supply Year, the amounts determined pursuant to clauses (ii), (iii) and (iv) above are to be appropriately adjusted to evenly apportion any increase or decrease over the remaining months of such Power Supply Year. For a further discussion of the Agency's budgeting process, see "Budgeting" below and "Annual Budget" in APPENDIX A hereto.

The Agency allocates the minimum cost component of Monthly Power Costs among the Generation Station, the Northern Transmission System and the Southern Transmission System in accordance with an Operating Cost Allocation Procedure approved by the Coordinating Committee and the Agency's Board of Directors. Under the Power Sales Contracts, the amount of Monthly Power Costs to be paid by each Power Purchaser for any month is the sum of: (i) its Generation Cost Share times the minimum cost component for such month allocated to the Generation Station; (ii) its Northern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Northern Transmission System; (iii) its Southern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Southern Transmission System; and (iv) the percentage of the energy delivered from the Project to it during the preceding month times the variable cost component. See "FISCAL YEAR 2021-2022 ANNUAL BUDGET" below.

On May 22, 2000, the Coordinating Committee adopted by resolution a "Fuel Acquisition and Transportation Cost Billing Procedure for Fiscal Year 2000-2001 and Thereafter" (the "Billing Procedure"). Pursuant to the Billing Procedure the Coordinating Committee has taken the following actions with respect

to the 2000-2001 fiscal year and each fiscal year thereafter and the Agency intends to continue to take such actions unless and until the Billing Procedure is repealed or modified to provide otherwise: (i) approved, pursuant to the authority delegated to the Coordinating Committee under the Power Sales Contracts, the inclusion in the minimum cost component of Monthly Power Costs of the minimum or guaranteed payments that the Agency is required to make under certain coal purchase contracts to which it is a party; (ii) directed that there be included in the variable cost component, rather than the minimum cost component, of Monthly Power Costs, transportation costs with respect to coal the cost of which is included in the variable cost component of Monthly Power Costs; (iii) approved a procedure for billing the variable cost component of Monthly Power Costs based upon the energy produced by the burning of coal the cost of which is included in the variable cost component; and (iv) approved a procedure permitting any Power Purchaser, to the extent that it does not schedule all of the energy produced by the burning of the coal the cost of which is included in its pro rata share of the minimum cost component of Monthly Power Costs during a particular month (an "Underburn Energy Balance"), to "bank" such energy for scheduling during subsequent months of the same fiscal year. From time to time subsequent to its adoption of the Billing Procedure, the Coordinating Committee has elected, pursuant to the Power Sales Contracts, to treat for billing purposes other coal purchase contracts to which the Agency is a party in the same manner as those referenced in the immediately preceding clause (i).

On August 21, 2012, the Coordinating Committee amended the Billing Procedure to make technical changes and to permit each Power Purchaser to "bank" an Overburn Energy Balance. The amendment provides that an "Overburn Energy Balance" is equal to the amount by which the energy scheduled by such Power Purchaser for a month exceeds the energy produced by the burning of the coal the cost of which is included in its pro rata share of the minimum cost component of Monthly Power Costs during such month. Each Power Purchaser may apply its Overburn Energy Balance to the extent of such balance to offset, during the same fiscal year in which such Overburn Energy Balance accrued, any future Underburn Energy Balance.

The Agency believes that the implementation of the Billing Procedure resulted in utilization levels of the Project that were higher than if the Billing Procedure had not been in effect. Although the Agency believes that the 2012 amendment to the Billing Procedure will reduce the incentive of the Power Purchasers to schedule power during the latter part of any Power Supply Year, the Agency expects that the continued implementation of the Billing Procedure will continue to result in utilization levels of the Project that are higher than if the Billing Procedure were not in effect. This is due in part to the Power Purchasers being able to use an Overburn Energy Balance (which is more likely to accrue during the first part of a Power Supply Year) to offset an Underburn Energy Balance (which is more likely to occur during the middle months of a Power Supply Year).

Year-End Reconciliation. Within 120 days after the end of each Power Supply Year, the Agency is required to submit to each Power Purchaser a statement of the actual aggregate Monthly Power Costs and other amounts payable under the Power Sales Contracts for all months of such year and any adjustments to such costs and amounts for any prior year, based on the annual audit required by the Power Sales Contracts. If for any Power Supply Year the actual aggregate Monthly Power Costs and other amounts payable under the Power Sales Contracts exceed the amount which the Power Purchasers have been billed, the Power Purchasers shall promptly pay the amount of such excess to the Agency. If such costs and other amounts, for any Power Supply Year, are less than the amounts billed, the Agency will credit the excess against the Power Purchasers' next monthly payments.

See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" in APPENDIX B hereto.

Renewal Power Sales Contracts

General. Under the Renewal Power Sales Contracts, from and after the Transition Date, the Renewal Power Purchasers are entitled to Project (as defined in the Renewal Power Sales Contracts) generation and transmission capabilities based on their respective Generation Entitlement Shares and transmission entitlements and are obligated to make payments therefor.

Each Renewal Power Sales Contract between the Agency and a Renewal Power Purchaser constitutes an obligation of the parties until the terms of all of the Renewal Power Sales Contracts expire on June 16, 2077. As long as any Bonds or Subordinated Indebtedness is outstanding or until provision has been made for the payment of all outstanding Bonds and Subordinated Indebtedness, the Renewal 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 that are pledged as security for Bonds and Subordinated Indebtedness or which will impair or adversely affect the rights of the holders of Bonds or Subordinated Indebtedness.

Payments are to be made by the Renewal Power Purchasers on a "take-or-pay" basis; that is, whether or not the Project or any part thereof is operating or 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 Renewal Power Sales Contracts constitute operating expenses of the respective Renewal Power Purchasers payable solely from their electric revenue funds.

Each Renewal Power Purchaser has covenanted in its Renewal Power Sales Contract, from and after the Transition Date, 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 and other available funds, are adequate to enable it to pay to the Agency all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues. See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS – Nature of Obligation" in APPENDIX B hereto.

The Renewal Power Sales Contracts provide that the obligations of the respective Power Purchasers are several and not joint. A failure by a Renewal Power Purchaser to make payments when due under its Renewal Power Sales Contract may result in larger payments being made by the other Renewal Power Purchasers in subsequent periods for the purpose of enabling the Agency to pay operating expenses, debt service and other costs of the Project and to maintain required reserves therefor. To the extent the amount to be paid by the non-paying Renewal Power Purchaser is not offset by revenues from sales of power or transmission service derived by the Agency in respect of such non-paying Renewal Power Purchaser's Generation Entitlement Share or transmission entitlement, such non-payment may result in deficits in funds and accounts established under the Resolution. In such event, the Agency would be required to amend, in accordance with the Renewal Power Sales Contracts and the Resolution, the Annual Budget (as defined in the Renewal Power Sales Contracts) to provide increases in subsequent billings to all Renewal Power Purchasers, including the non-paying Renewal Power Purchaser, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Renewal Power Purchaser's Generation Entitlement Share or transmission entitlement to the other Renewal Power Purchasers. Amounts thereafter collected from such non-paying Renewal Power Purchaser are to be credited against the next billings of such other Renewal Power Purchasers as appropriate. In the event, however, of a termination of the Project and a resultant default by the Agency under the Resolution, each Power Purchaser would, under its Power Sales Contract, be severally obligated to pay only its respective Generation Cost Share (as defined in the Renewal Power Sales Contracts) and Transmission Cost Share (as defined in the Renewal Power Sales Contracts), if any, of the debt service on Bonds and on Subordinated Indebtedness, as well as other fixed costs.

In the event of a default or inability to perform by a Renewal Power Purchaser under its Renewal Power Sales Contract, the Agency may proceed to enforce the Renewal Power Purchaser's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or in equity. The Renewal Power Sales Contracts also provide that if a payment due under the Renewal Power Sales Contracts remains unpaid when due, the Agency may, upon 120 days' written notice to the Renewal Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Renewal Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Renewal Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities, the discontinuance by the Agency of delivery of capacity and energy to and the use of the Project facilities by a defaulting Renewal Power Purchaser will not reduce the obligation of such Renewal Power Purchaser to make payments under its Renewal Power Sales Contract. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – California Greenhouse Gas Initiatives" below.

See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS" in APPENDIX B hereto.

Monthly Power Costs. During each Power Supply Year (as defined in the Renewal Power Sales Contracts) occurring from and after the Transition Date, each Renewal Power Purchaser is obligated to pay its share of Monthly Power Costs (as defined in the Renewal Power Sales Contracts), which, generally, consist of all of the Agency's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Project, to the extent not paid from the proceeds of Bonds and Subordinated Indebtedness or from notes or other evidences of indebtedness issued in anticipation thereof. Such costs, which consist of a minimum cost component and a variable cost component, are billed monthly. Power Supply Years coincide with the Agency's fiscal years, which, from and after the Transition Date, end on June 30.

The minimum cost component is to be billed each month occurring from and after the Transition Date for the then current month based on the estimates contained in the Annual Budget prepared by the Agency prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each such month, the minimum cost component includes:

(i) the amounts which the Resolution requires the Agency to pay or deposit during such month into funds or accounts for debt service on, and reserve requirements for, Bonds and Subordinated Indebtedness;

(ii) one-twelfth of the amount which the Agency is required under the Resolution to pay or deposit during the Power Supply Year which includes such month into any other fund or account established by the Resolution, including any amount needed to eliminate a deficiency in any fund established under the Resolution whether or not resulting from a default in payments by any Renewal Power Purchaser of amounts due under any Renewal Power Sales Contract;

(iii) one-twelfth of the costs of producing and delivering capacity and energy from the Project during the Power Supply Year which includes such month, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of natural gas procured by the Agency for use in the Generation Station (as defined in the Renewal Power Sales Contracts) ("Project Fuel") (but excluding, from the Monthly Power Costs of Renewal Power Purchasers who elect to procure their own fuel, minimum or guaranteed contract payments that the Renewal Contract Coordinating Committee has determined to include in the minimum cost component and excluding for such procuring Renewal Power Purchasers the transportation costs for Project Fuel); and

(iv) one-twelfth of the amount necessary during the Power Supply Year which includes such month to pay or provide reserves for payment of amounts required to be paid pursuant to the

Act to counties, municipalities and school districts affected by the Project, Tax Equivalent Payments (as defined in the Renewal Power Sales Contracts) and all other taxes which the Agency is required to pay.

The variable cost component is to be billed each month for the immediately preceding month occurring from and after the Transition Date. The variable cost component of Monthly Power Costs consists of all costs of Project Fuel that was used to generate a Renewal Power Purchaser's Generation Entitlement Share and that was not included in the minimum cost component.

If there is any revision of the Annual Budget after the commencement of any Power Supply Year occurring from and after the Transition Date, the amounts determined pursuant to clauses (ii), (iii) and (iv) above are to be appropriately adjusted to evenly apportion any increase or decrease over the remaining months of such Power Supply Year. Subject to the election by Renewal Power Purchasers to procure their own fuel and any modifications provided in the Fuel Management Practices and Procedures (as defined in the Renewal Power Sales Contracts), as described below, the Agency anticipates following the same budgeting process from and after the Transition Date as that described in "Budgeting" below and "Annual Budget" in APPENDIX A hereto.

The Agency is to allocate the minimum cost component of Monthly Power Costs among the Generation Station (as defined in the Renewal Power Sales Contracts), the Northern Transmission System (as defined in the Renewal Power Sales Contracts) and the Southern Transmission System (as defined in the Renewal Power Sales Contracts) in accordance with the Renewal Power Sales Contracts. Under the Renewal Power Sales Contracts, the amount of Monthly Power Costs to be paid by each Power Purchaser for any month occurring from and after the Transition Date is the sum of: (i) its Generation Cost Share times the minimum cost component for such month allocated to the Generation Station; (ii) its Northern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Northern Transmission System; (iii) its Southern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Southern Transmission System; and (iv) the percentage of the energy delivered from the Project to it during the preceding month times the variable cost component.

The Renewal Power Sales Contracts contemplate the adoption of Fuel Management Practices and Procedures (as defined in the Renewal Power Sales Contracts). To the extent that any of the Fuel Management Practices and Procedures modifies the payment responsibility of any of the Renewal Power Purchasers for costs of Project Fuel acquisition or the costs of Project Fuel transmission or transportation, as then determined under the Renewal Power Sales Contracts, then such modification would require affirmation by Renewal Contract Coordinating Committee representatives of Purchasers having Voting Rights (as defined in the Renewal Power Sales Contracts) equal to 100%. The Renewal Contract Coordinating Committee approved the Hydrogen Billing Procedure as part of the Fuel Management Practices and Procedures.

Year-End Reconciliation. Within 120 days after the end of each Power Supply Year, the Agency is required to submit to each Renewal Power Purchaser a statement of the actual aggregate Monthly Power Costs and other amounts payable under the Renewal Power Sales Contracts for all months of such year and any adjustments to such costs and amounts for any prior year, based on the annual audit required by the Renewal Power Sales Contracts. If for any Power Supply Year the actual aggregate Monthly Power Costs and other amounts payable under the Renewal Power Sales Contracts exceed the amount which the Renewal Power Purchasers have been billed, the Renewal Power Purchasers shall promptly pay the amount of such excess to the Agency. If such costs and other amounts, for any Power Supply Year, are less than the amounts billed, the Agency will credit the excess against the Renewal Power Purchasers' next monthly payments.

See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS" in APPENDIX B hereto.

Excess Power Sales Agreement

Because a portion of the capability of the Project purchased by the Utah Purchasers (as defined in the Excess Power Sales Agreement) was expected to be surplus to their needs, these Power Purchasers each entered into the Excess Power Sales Agreement in 1980, pursuant to which they may sell their respective excess Generation Entitlement Shares to the Excess Power Purchasers. Payments by the Excess Power Purchasers under such agreement are to be made monthly to Utah Associated Municipal Power Systems ("UAMPS"), successor to Intermountain Consumer Power Association ("ICPA"), as agent for the sellers under the Excess Power Sales Agreement, and forwarded promptly by it to the Agency for the accounts of the respective sellers. The Excess Power Sales Agreement does not reduce or modify the obligations of such Utah Purchasers under their Power Sales Contracts.

See "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers" above for a discussion of certain recalls of Project capability made by certain of the Utah Purchasers and the status of the entitlements to Project capability of the remaining Utah Purchasers.

For a discussion of certain additional provisions of the Excess Power Sales Agreement, including those relating to adjustments of the amounts of capacity sold thereunder, see "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in APPENDIX B hereto.

Agreement for Sale of Renewal Excess Power

Because a portion of the capability of the Project (as defined in the Renewal Power Sales Contracts) purchased by the Utah Purchasers (as defined in the Renewal Power Sales Contracts) was expected still to be surplus to their needs from and after the Transition Date, these Renewal Power Purchasers each entered into the Agreement for Sale of Renewal Excess Power in 2017, pursuant to which they may sell their respective excess Generation Entitlement Shares to the Department. Payments by the Department under such agreement are to be made monthly to the Agency, as agent for the sellers under the Agreement for Sale of Renewal Excess Power, for the accounts of the respective sellers. The Agreement for Sale of Renewal Excess Power does not reduce or modify the obligations of such Utah Purchasers under their Renewal Power Sales Contracts.

The Agreement for Sale of Renewal Excess Power permits the Utah Purchasers to recall all or a portion of the entitlement that they have sold to the Department. Recalls under the Agreement for Sale of Renewal Excess Power are made with respect to a "Summer Season" or a "Winter Season" (each a "Season"). The Agreement for Sale of Renewal Excess Power defines a "Summer Season" as each period beginning at 12:01 a.m. on June 1 and ending at 12:01 a.m. on the following October 1 and a "Winter Season" as each period beginning at 12:01 a.m. on October 1 and ending at 12:01 a.m. on the following June 1.

Based on the current schedules of power to be sold under the Agreement for Sale of Renewal Excess Power, which schedules are to be revised, if at all, at least twelve months prior to the Transition Date and, thereafter, upon notice to be provided at least twelve months prior to the commencement of any Season, the Utah Purchasers have elected to sell to the Department, commencing on the Transition Date, all of their Project capability. Any election by a Utah Purchaser to sell such Project capability must remain in effect for three calendar years following the commencement of the Season with respect to which such election has been made. The Utah Purchasers may recall all or a portion of such Project capability over the course of at least two calendar years following the expiration of such three-calendar-year period.

For a discussion of certain additional provisions of the Agreement for Sale of Renewal Excess Power, including those relating to adjustments of the amounts of capacity sold thereunder, see "SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR SALE OF RENEWAL EXCESS POWER" in APPENDIX B hereto.

Budgeting

The Power Sales Contracts and, from and after the Transition Date, the Renewal Power Sales Contracts require the Agency to adopt an Annual Budget at least 30 days but not more than 45 days prior to the beginning of each Power Supply Year (as defined, prior to the Transition Date, in the Power Sales Contracts and, from and after the Transition Date, the Renewal Power Sales Contracts) and permit the amendment of the Annual Budget (as defined, prior to the Transition Date, in the Power Sales Contracts and, from and after the Transition Date, the Renewal Power Sales Contracts) from time to time thereafter. Each such budget is to set forth a detailed estimate of the Monthly Power Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Power Supply Year. See "Power Sales Contracts" above. The Resolution requires the Agency to adopt Annual Budgets, and amendments to such Annual Budgets, as and when required by the Power Sales Contracts. See "FISCAL YEAR 2021-2022 ANNUAL BUDGET" below.

Generation Renewal Project

To facilitate the continued involvement of the California Purchasers in the Project following the termination of the Power Sales Contracts (provided to occur on June 15, 2027), the Agency and each of the Power Purchasers amended the Power Sales Contracts to provide for the Gas Repowering. The Power Sales Contracts, as so amended, provide for the Gas Repowering to be completed by July 1, 2025. The Power Sales Contracts, as so amended, also provide that the costs of retiring and decommissioning facilities of the Project that are not used in the Gas Repowering are to be funded through indebtedness to be incurred by the Agency in connection with the Gas Repowering.

Section 45 of the Power Sales Contracts, as so amended, further provide that in the event the Gas Repowering is not undertaken as provided in the Power Sales Contracts, and there is no Transition Project Indebtedness, as defined in the Power Sales Contracts, outstanding, the Project would consist of transmission facilities with sufficient generation capacity to support such transmission facilities. The entitlements to such facilities would be sold to the Power Purchasers who elect to renew their entitlements in the Project pursuant to a transmission services agreement. The California Renewal Purchasers would be offered 100% of the entitlements in the Southern Transmission System and 60% of the entitlements in the Northern Transmission System. The Utah Renewal Purchasers would be offered 40% of the entitlements in the Northern Transmission System. The term of the Power Sales Contracts would be extended to the earlier of the completion of decommissioning and retirement of the facilities not necessary to maintain and support such transmission facilities and January 1, 2032. In that event, the Renewal Power Sales Contracts and the Agreement for Sale of Renewal Excess Power would terminate.

The 2022 Series A and B Bonds will constitute Transition Project Indebtedness. Accordingly, the Agency believes that the provisions of Section 45 of the Renewal Power Sales Contracts will not become operative.

See "INTRODUCTORY STATEMENT – The Project and the Generation Renewal Project" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" above and "ELECTRIC INDUSTRY RESTRUCTURING – California Electric Energy Actions – *California Political Environment*" and "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – California Greenhouse Gas Initiatives" and" INTERMOUNTAIN POWER AGENCY – The Interlocal Cooperation Act" below and "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in APPENDIX B hereto.

Hydrogen Facilities

The Agency has contracted for the Hydrogen Facilities which consist of (a) the Hydrogen Betterments that are expected to minimize the costs associated with increasing the capabilities of the gas units to burn a fuel mix including green hydrogen, and (b) the Hydrogen Conversion and Storage Capacity to provide hydrogen fuel production and storage for use in connection with the Hydrogen Betterments. See "INTRODUCTORY STATEMENT – Hydrogen Facilities" above.

Other Amendments to Material Contracts

The Agency and the Department have negotiated the amendment and restatement of the Construction Management and Operating Agreement for changes required as a result of the amendment of the Power Sales Contracts and the execution of the Renewal Power Sales Contracts as well as other changes that are desirable to update the relationship between the Agency and the Department, in the Department's capacities as Project Manager and Operating Agent. Such amendment and restatement is in the process of receiving approval of the necessary governing bodies of the Department. See "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT" in APPENDIX B hereto.

The Agency has amended its organizational documents from time to time to extend the Agency's existence, to facilitate the Generation Renewal Project and to update such documents to conform to changes in Utah law.

DESCRIPTION OF THE 2022 SERIES A AND B BONDS

General

The 2022 Series A Bonds will be issued in the aggregate principal amount of $732,755,000 and the 2022 Series B Bonds will be issued in the aggregate principal amount of $64,850,000. The 2022 Series A and B Bonds will be dated the date of the delivery thereof, and will bear interest from that date payable on July 1, 2022 and each January 1 and July 1 thereafter until maturity. Interest shall be calculated on the basis of a 360-day year consisting of twelve 30-day months. The 2022 Series A and B Bonds will mature on July 1 in the years and the principal amounts and bear interest at the rates set forth on the inside front cover of this Official Statement. The 2022 Series A and B Bonds will be issuable only in fully registered form in the principal amount of $5,000 and integral multiples thereof. Upon initial issuance, the 2022 Series A and B Bonds will be issued in book-entry only form and will be registered in the name of Cede & Co., as nominee for DTC. See "Book-Entry Only System" below.

The principal of the 2022 Series A and B Bonds will be payable at the principal office of the Paying Agent and interest on any 2022 Series A and B Bond will be paid on each interest payment date to the person in whose name such Bond is registered on the applicable Record Date, which is the close of business on the fifteenth (15th) day (whether or not a business day) of the calendar month next preceding such interest payment date; *provided, however*, that so long as the 2022 Series A and B Bonds are subject to the book-entry only system of registration and transfer described in "Book-Entry Only System" below, all payments with respect to the principal of, and interest on, the 2022 Series A and B Bonds will be made to DTC.

Book-Entry Only System

General

The 2022 Series A and B Bonds will be available only in book-entry form. DTC will act as the initial securities depository for the 2022 Series A and B Bonds. The 2022 Series A and B Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered bond certificate will be issued in the aggregate principal amount of the 2022 Series A and B Bonds of each maturity (and, if applicable, each interest rate within a maturity), and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of 2022 Series A and B Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for such Bonds on DTC's records. The ownership interest of each actual purchaser of each 2022 Series A and B Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2022 Series A and B 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 2022 Series A and B Bonds, except in the event that use of the book-entry system for the 2022 Series A and B Bonds is discontinued.

SO LONG AS CEDE & CO. (OR ANY OTHER NOMINEE REQUESTED BY DTC) IS THE REGISTERED OWNER OF THE 2022 SERIES A AND B BONDS, AS NOMINEE FOR DTC, REFERENCES HEREIN TO THE HOLDERS OR REGISTERED OWNERS OR OWNERS OF THE 2022 SERIES A AND B BONDS WILL MEAN CEDE & CO. (OR SUCH OTHER NOMINEE), AS AFORESAID, AND WILL NOT MEAN THE BENEFICIAL OWNERS.

To facilitate subsequent transfers, all 2022 Series A and B Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of 2022 Series A and B Bonds with

DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2022 Series A and B Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 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.

The Agency, the Trustee and the Bond Registrar and Paying Agent for the 2022 Series A and B Bonds may treat DTC (or its nominee) as the sole and exclusive owner of the 2022 Series A and B Bonds registered in its name for the purpose of: payment of the principal of or interest on the 2022 Series A and B Bonds; giving any notice permitted or required to be given to Holders under the Resolution; registering the transfer of 2022 Series A and B Bonds; obtaining any consent or other action to be taken by Holders; and for all other purposes whatsoever, and shall not be affected by any notice to the contrary. Neither the Agency nor the Trustee nor the Bond Registrar nor the Paying Agent for the 2022 Series A and B Bonds nor the Underwriters (other than in their capacity, if any, as Direct Participants or Indirect Participants) will have any responsibility or obligation to any Direct Participant, any person claiming a beneficial ownership interest in the 2022 Series A and B Bonds under or through DTC or any Direct Participant, or any other person which is not shown on the registry books of the Agency (kept by the Bond Registrar for the 2022 Series A and B Bonds) as being a Holder, with respect to: the accuracy of any records maintained by DTC or any Direct or Indirect Participant regarding ownership interests in the 2022 Series A and B Bonds; the payment by DTC or any Direct or Indirect Participant of any amount in respect of the principal of or interest on the 2022 Series A and B Bonds; the delivery to any Direct or Indirect Participant or any Beneficial Owner of any notice which is permitted or required to be given to Holders under the Resolution; or any consent given or other action taken by DTC as a Holder of the 2022 Series A and B Bonds.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to 2022 Series A and B 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 issuer 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 securities, such as the 2022 Series A and B Bonds, are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Except as described below, neither DTC nor Cede & Co. nor any other nominee of DTC will take any action to enforce covenants with respect to any security registered in the name of Cede & Co. or any other nominee of DTC. Under its current procedures, on the written instructions of a Direct Participant given in accordance with DTC's procedures, DTC will cause Cede & Co. to sign a demand to exercise certain bondholder rights. In accordance with DTC's current procedures, Cede & Co. will sign such document only as record holder of the quantity of securities referred to therein (which is to be specified in the Direct Participant's request to DTC for such document) and not as record holder of all the securities of that issue registered in the name of Cede & Co. Also, in accordance with DTC's current procedures, all factual representations to the issuer or any other party to be made by Cede & Co. in such document must be made to DTC and Cede & Co. by the Direct Participant in its request to DTC.

For so long as the 2022 Series A and B Bonds are issued in book-entry form through the facilities of DTC, any Beneficial Owner desiring to cause the Agency to comply with any of its obligations with respect to the 2022 Series A and B Bonds must make arrangements with the Direct Participant or Indirect Participant through whom such Beneficial Owner's ownership interest in the 2022 Series A and B Bonds is recorded in order for the Direct Participant in whose DTC account such ownership interest is recorded to make the request of DTC described above.

NEITHER THE AGENCY NOR THE TRUSTEE NOR THE BOND REGISTRAR NOR THE PAYING AGENT FOR THE 2022 SERIES A AND B BONDS NOR THE UNDERWRITERS (OTHER THAN IN THEIR CAPACITY, IF ANY, AS DIRECT PARTICIPANTS OR INDIRECT PARTICIPANTS) WILL HAVE ANY OBLIGATION TO THE DIRECT PARTICIPANTS OR THE

INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO DTC'S PROCEDURES OR ANY PROCEDURES OR ARRANGEMENTS BETWEEN DIRECT PARTICIPANTS, INDIRECT PARTICIPANTS AND THE PERSONS FOR WHOM THEY ACT RELATING TO THE MAKING OF ANY DEMAND BY CEDE & CO. AS THE REGISTERED OWNER OF THE 2022 SERIES A AND B BONDS, THE ADHERENCE TO SUCH PROCEDURES OR ARRANGEMENTS OR THE EFFECTIVENESS OF ANY ACTION TAKEN PURSUANT TO SUCH PROCEDURES OR ARRANGEMENTS.

Principal of and interest on the 2022 Series A and B Bonds will be paid 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 Agency or the Paying Agent, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Agency or the Paying Agent for the 2022 Series A and B Bonds, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Paying Agent for the 2022 Series A and B Bonds, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

As long as the book-entry system is used for the 2022 Series A and B Bonds, the Bond Registrar for the 2022 Series A and B Bonds will give any notices required to be given to Holders of 2022 Series A and B Bonds only to DTC. Any failure of DTC to advise any Direct Participant, or of any Direct Participant to notify any Indirect Participant, or of any Direct or Indirect Participant to notify any Beneficial Owner, of any such notice and its content or effect will not affect the validity of any action premised on such notice.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of 2022 Series A and B Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2022 Series A and B Bonds, such as tenders, defaults, and proposed amendments to the Resolution. For example, Beneficial Owners of the 2022 Series A and B Bonds may wish to ascertain that the nominee holding the 2022 Series A and B Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners.

NEITHER THE AGENCY NOR THE TRUSTEE NOR THE BOND REGISTRAR OR THE PAYING AGENT FOR THE 2022 SERIES A AND B BONDS NOR THE UNDERWRITERS (OTHER THAN IN THEIR CAPACITY, IF ANY, AS DIRECT PARTICIPANTS OR INDIRECT PARTICIPANTS) WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT PARTICIPANTS, OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES, WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR THE DIRECT PARTICIPANTS, THE INDIRECT PARTICIPANTS, OR THE BENEFICIAL OWNERS.

For every transfer and exchange of a beneficial ownership interest in the 2022 Series A and B Bonds, a Beneficial Owner may be charged a sum sufficient to cover any tax, fee or other governmental charge that may be imposed in relation thereto.

Discontinuation of the Book-Entry System

DTC may determine to discontinue providing its services as depository with respect to the 2022 Series A and B Bonds at any time by giving reasonable notice to the Agency or the Trustee. In addition, if

the Agency determines that (i) DTC is unable to discharge its responsibilities with respect to the 2022 Series A and B Bonds, or (ii) continuation of the system of book-entry transfers through DTC is not in the best interests of the Beneficial Owners of the 2022 Series A and B Bonds or of the Agency, the Agency may, upon satisfaction of the applicable procedures of DTC with respect thereto, terminate the services of DTC with respect to the 2022 Series A and B Bonds. Upon the resignation of DTC or determination by the Agency that DTC is unable to discharge its responsibilities, the Agency may, within 90 days, appoint a successor depository. If no such successor is appointed or the Agency determines to discontinue the book-entry system, 2022 Series A and B Bond certificates will be printed and delivered. Transfers and exchanges of 2022 Series A and B Bonds will thereafter be made as described under "Interchangeability" below.

If the book-entry system is discontinued, the persons to whom 2022 Series A and B Bond certificates are delivered will be treated as "Holders" for all purposes of the Resolution, including without limitation the payment of principal of, and interest on, 2022 Series A and B Bonds and the giving to the Agency of any notice, consent, request or demand pursuant to the Resolution for any purpose whatsoever. In such event, interest on such 2022 Series A and B Bonds will be payable by check or draft of the Trustee as the Paying Agent for the 2022 Series A and B Binds mailed to such Holders at the addresses shown on the registry books of the Agency kept for that purpose at the principal corporate trust office of the Trustee, as Bond Registrar for the 2022 Series A and B Bonds, and the principal of all 2022 Series A and B Bonds will be payable at the principal corporate trust office of the Trustee, as the Paying Agent for the 2022 Series A and B Bonds.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that the Agency believes to be reliable. No representation is made herein by the Agency or the Underwriters as to the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date of this Official Statement.

Redemption

Optional Redemption

***2022 Series A Bonds*.** The 2022 Series A Bonds maturing on or after July 1, 2032 are subject to redemption prior to maturity at the option of the Agency, as a whole or in part, at any time on or after July 1, 2031, at a redemption price equal to 100% of the principal amount of 2022 Series A Bonds or portions thereof to be redeemed, plus accrued interest to the redemption date.

***2022 Series B Bonds*.** The 2022 Series B Bonds maturing on or after July 1, 2033 are subject to redemption prior to maturity at the option of the Agency, as a whole or in part (and if in part on a *pro rata* basis), at any time on or after July 1, 2032, at a redemption price equal to 100% of the principal amount of 2022 Series B Bonds or portions thereof to be redeemed, plus accrued interest to the redemption date.

The 2022 Series B Bonds also are subject to redemption prior to maturity at the option of the Agency, as a whole or in part (and if in part on a *pro rata* basis), at any time before July 1, 2032, on any Business Day, at the Make-Whole Redemption Price (defined below) determined by the Designated Investment Banker (defined below).

The "*Make-Whole Redemption Price*" is the greater of (1) the issue price as shown on the inside cover page of this Official Statement (but not less than 100% of the principal amount) of the 2022 Series B Bonds to be redeemed, or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2022 Series B Bonds to be redeemed to the maturity date, not including any portion of those payments of interest accrued and unpaid as of the date on which the 2022 Series B Bonds are to be redeemed, discounted to the date on which such 2022 Series B Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below)

plus 35 basis points, plus accrued and unpaid interest on the 2022 Series B Bonds to be redeemed on the redemption date.

"*Business Day*" means (i) a day other than a day on which commercial banks located in New York, New York or cities in which the designated office of the Trustee or the Paying Agent for the 2022 Series A and B Bonds are required or authorized by law to close and (ii) a day other than a day on which the New York Stock Exchange is closed.

"*Treasury Rate*" means, with respect to any redemption date for a particular 2022 Series B Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Yield (defined below), as calculated by the Designated Investment Banker (defined below).

"*Comparable Treasury Issue*" means, with respect to any Valuation Date (defined below) for a redemption date for a particular 2022 Series B Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the 2022 Series B Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such 2022 Series B Bonds to be redeemed.

"*Comparable Treasury Yield*" means, with respect to any Valuation Date for a redemption date for a particular 2022 Series B Bond, (1) the most recent yield data for the applicable U.S. Treasury maturity index from the Federal Reserve Statistical Release H.15 Daily Update (or any comparable or successor publication) reported, as of 11:00 a.m. New York City time, on the Valuation Date; or (2) if the yield described in (1) above is not reported as of such time or the yield reported as of such time is not ascertainable, the average of five Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or if the Designated Investment Banker obtains fewer than five (5) Reference Treasury Dealer Quotations, the average of all such quotations.

"*Designated Investment Banker*" means one of the Reference Treasury Dealers appointed by the Agency.

"*Reference Treasury Dealer*" means each of five (5) firms, specified by the Agency from time to time, that are primary U.S. Government securities dealers in the City of New York (each, a "*Primary Treasury Dealer*"); *provided, however*, that if any of them ceases to be a Primary Treasury Dealer, the Agency will substitute another Primary Treasury Dealer.

"*Reference Treasury Dealer Quotations*" means, with respect to each Reference Treasury Dealer and any redemption date for a particular 2022 Series B Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Agency and the Trustee by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

"*Valuation Date*" means a date that is no earlier than four (4) days prior to the date the redemption notice is to be mailed and no later than the date the redemption notice is to be mailed.

Sinking Fund Redemption – 2022 Series B Bonds

The 2022 Series B Bonds maturing on July 1, 2045 (the "2022 Series B 2045 Term Bonds") are subject to redemption through sinking fund installments on July 1 of each of the years set forth in the table below. The redemption price will be 100 percent of the principal amount of the 2022 Series B 2045 Term

Bonds so to be redeemed plus accrued interest, if any, to the redemption date. Such sinking fund installments will be sufficient to redeem the following principal amounts of the 2022 Series B 2045 Term Bonds:

$33,210,000 2022 Series B 2045 Term Bonds

July 1	Principal Amount
2038	$3,445,000
2039	3,630,000
2040	3,820,000
2041	4,020,000
2042	4,230,000
2043	4,450,000
2044	4,685,000
2045†	4,930,000

† Maturity

Selection of 2022 Series A and B Bonds to be Redeemed

2022 Series A Bonds. If less than all of the 2022 Series A Bonds are to be redeemed, the Agency may select the maturity or maturities to be redeemed. If less than all of the 2022 Series A Bonds of any maturity are to be redeemed, the particular 2022 Series A Bonds or portions of 2022 Series A Bonds of such maturity to be redeemed shall be selected at random by the Trustee in such manner as the Trustee in its discretion may deem fair and appropriate. The portion of any 2022 Series A Bond of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or an integral multiple thereof, and in selecting portions of 2022 Series A Bonds for redemption, the Trustee will treat each 2022 Series A Bond as representing that number of 2022 Series A Bonds of $5,000 denomination which is obtained by dividing the principal amount of such 2022 Series A Bond to be redeemed in part by $5,000.

2022 Series B Bonds. If less than all of the 2022 Series B Bonds are called for optional redemption, the Agency will designate the maturities, including any sinking fund redemptions of 2022 Series B Term Bonds, from which the 2022 Series B Bonds are to be redeemed. For so long as the 2022 Series B Bonds are registered in book-entry form and DTC or a successor securities depository is the sole registered owner of such 2022 Series B Bonds, if fewer than all of the 2022 Series B Bonds of the same maturity and bearing the same interest rate are to be redeemed, whether through optional or mandatory sinking fund redemptions, the particular 2022 Series B Bonds to be redeemed shall be selected on a *pro rata* pass-through distribution of principal basis in accordance with the operational arrangements of DTC then in effect, and if the DTC operational arrangements do not allow for redemption on a *pro rata* pass-through distribution of principal basis, all 2022 Series B Bonds to be so redeemed will be selected for redemption in accordance with DTC procedures by lot; *provided, however*, that any such redemption must be performed such that all 2022 Series B Bonds remaining Outstanding will be in authorized denominations.

In connection with any payment of principal of the 2022 Series B Bonds pursuant to the pass-through distribution of principal as described above, the Trustee will direct DTC to make a pass-through distribution of principal to the beneficial owners of the 2022 Series B Bonds.

For purposes of calculating *pro rata* pass-through distributions of principal, "*pro rata*" means, for any amount of principal or interest to be paid, the application of a fraction to such amounts where (a) the numerator is equal to the amount due to the owners of the 2022 Series B Bonds on a payment date, and (b) the denominator is equal to the total original par amount of the 2022 Series B Bonds.

It is the Agency's intent that redemption allocations made by DTC with respect to the 2022 Series B Bonds be made on a *pro rata* pass-through distribution of principal basis as described above. However, the Agency cannot provide any assurance that DTC, DTC's direct and indirect participants, or any other intermediary will allocate the redemption of such 2022 Series B Bonds on such basis.

If the 2022 Series B Bonds are not registered in book-entry form and if fewer than all of the 2022 Series B Bonds of the same maturity and bearing the same interest rate are to be redeemed, the 2022 Series B Bonds of such maturity and bearing such interest rate to be redeemed will be selected on a *pro rata* basis; *provided, however*, that any such redemption must be performed such that all 2022 Series B Bonds remaining Outstanding will be in authorized denominations.

Notice of Redemption

The Resolution requires the Trustee to give notice of any redemption of the 2022 Series A and B Bonds by first class mail, postage prepaid, not less than 30 days nor more than 60 days prior to the redemption date, to the Holders of any 2022 Series A or B Bonds or portions of 2022 Series A or B Bonds which are to be redeemed, at their last addresses, if any, appearing upon the registry books of the Agency (kept by the Trustee, as Bond Registrar for the 2022 Series A and B Bonds).

For so long as a book-entry system is in effect with respect to the 2022 Series A and B Bonds, the Trustee will mail notices of redemption of such 2022 Series A or B Bonds only to DTC or its nominee, or its successor, as the registered owner thereof. Any failure of DTC or its successor or a Direct Participant or Indirect Participant to so select particular ownership interests of 2022 Series A or B Bonds to be redeemed, or to notify a Beneficial Owner of a 2022 Series A or B Bond of any redemption will not affect the sufficiency or the validity of the redemption of the 2022 Series A or B Bonds. See "Book-Entry System" above. Neither the Agency nor the Trustee nor the Underwriters (other than in their capacity, if any, as Direct Participants or Indirect Participants) can make any assurance that DTC, the Direct Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the 2022 Series A and B Bonds, or that they will do so on a timely basis.

Interchangeability

If the book-entry system has been terminated with respect to the 2022 Series A and B Bonds, the 2022 Series A and B Bonds, upon surrender thereof at the principal corporate trust office of the Bond Registrar, with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the registered owner or the registered owner's duly authorized attorney, may be exchanged for an equal aggregate principal amount of the 2022 Series A or B Bonds, as applicable, of the same maturity (and, if applicable, interest rate within such maturity) of any authorized denominations.

In all cases in which the privilege of exchanging or transferring the 2022 Series A and B Bonds is exercised, the Agency will execute and the Bond Registrar for the 2022 Series A and B Bonds will authenticate and deliver replacement 2022 Series A or B Bonds, as applicable, in accordance with the provisions of the Resolution. For every such exchange or transfer of the 2022 Series A and B Bonds, the Agency or the Bond Registrar for the 2022 Series A and B Bonds may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer, but may impose no other charge therefor. Neither the Agency nor the Bond Registrar for the 2022 Series A and B Bonds will be required to transfer or exchange 2022 Series A and B Bonds for the period next preceding any interest payment date for the 2022 Series A and B Bonds beginning with the Record Date for such interest payment date and ending on such interest payment date.

Tax Covenants

In order to maintain the exclusion from gross income for federal income tax purposes of interest on the 2022 Series A Bonds, and for no other purpose, the Agency has covenanted to comply with each applicable requirement of the Internal Revenue Code of 1986 necessary to maintain such exclusion. So long as necessary in order to maintain the exclusion from federal gross income of interest on the 2022 Series A Bonds, these covenants will survive the payment of the 2022 Series A Bonds and the interest thereon, including any payment or defeasance thereof pursuant to the Resolution. Any amounts required to be paid by the Agency to the federal government pursuant to these covenants will be Operating Expenses for purposes of the Resolution and the Agency may provide for any such payment in its Annual Budget.

DEBT SERVICE REQUIREMENTS

Set forth in APPENDIX G hereto is a table showing the debt service requirements for the 2022 Series A and B Bonds.

ELECTRIC INDUSTRY RESTRUCTURING

General

Traditionally, and to ensure universal and cost-effective service, electric utilities have operated as heavily regulated monopolies. In recent decades, however, this regulatory climate has been changed dramatically. The Federal Power Act (the "FPA"), as amended by the Energy Policy Act of 1992 and as implemented by FERC, now encourages increased competition in the wholesale electric markets. The Energy Policy Act of 2005 also amended the FPA to make significant changes in federal regulation of the electric utility industry. Additionally, some states, such as California, have also enacted legislation for the purpose of increasing competition among electric utilities in the wholesale and retail markets. Since 2006, California has prohibited new long-term contracts for the purchase of power from sources that emit in excess of specified amounts of GHGs (effectively prohibiting such purchases from coal-fired plants). The general political climate in other states increasingly disfavors coal-fired power plants. The Agency continues to monitor policy statements and proposed legislation that may impact the Project.

The restructuring of the electric power industry, both nationally and in California, has had and may continue to have significant effects on the Agency, the Project and the Power Purchasers. As discussed in this Official Statement, the Agency and the Power Purchasers have taken certain actions in response to electric industry restructuring and expect to take additional actions in the future to ensure compliance with all applicable laws and regulations. Also, the Agency will continue to take actions to cause the Project to be operated consistent with the Construction Management and Operating Agreement, the Power Sales Contracts and Prudent Utility Practice (as defined in the Resolution). The Agency cannot, however, predict how the future business, affairs or financial condition of the Agency, the Project (including, without limitation, the demand for the Project's generating capacity or the utilization of the Project's transmission resources) or the Power Purchasers will be affected by such matters.

Federal Electric Energy Actions

Energy Policy Act of 1992. The Energy Policy Act of 1992 amended the FPA to effect fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission access. The purpose of these changes, in part, was to bring about increased competition. In particular, the Energy Policy Act of 1992 provided FERC with the authority, upon application by certain entities, to require a transmitting utility to provide transmission services to such applicants essentially on a cost-of-service basis. Municipally-owned electric utilities are "transmitting utilities" for purposes of these

provisions of the Energy Policy Act of 1992, thus arguably giving FERC limited jurisdiction over the Agency to the extent it is a transmitting utility (except with respect to limited circumstances not applicable to the Agency).

FERC Open-Access Transmission Initiatives. To effectuate the transmission access provisions of the Energy Policy Act of 1992, FERC issued two rules on April 24, 1996. The first of these rules, Order No. 888: (i) requires all "public utilities" (the term FERC uses for utilities that are generally subject to FERC regulations) to offer non-discriminatory, open-access transmission services to entities seeking to effect wholesale power transactions, under terms and conditions that are comparable to the services that they provide to themselves; and (ii) requires "non-public utilities" (the term FERC uses for utilities that are not generally subject to FERC regulations including municipal utilities, such as the Agency, and consumer-owned utilities) that purchase transmission services from a public utility to provide, in turn, non-discriminatory, open-access transmission services back to such public utility under terms and conditions that are comparable to the services that they provide to themselves (the requirement described in clause (ii) above that applies to non-public utilities is referred to herein as the "Reciprocity Requirement"). The second rule, Order No. 889: (i) implements standards of conduct to ensure that utilities that offer open-access transmission services and their affiliates do not have an unfair competitive advantage in using their position as a transmission services provider to sell power; and (ii) requires those utilities to share electronically (via the internet) important information regarding the pricing and availability of transmission services.

Order Nos. 888 and 889 also established a pro forma Open Access Transmission Tariff ("OATT") for adoption by public utilities. Non-public utilities may elect to file an OATT that complies with FERC's pro forma OATT on a voluntary basis for, among other reasons, the purpose of complying with the Reciprocity Requirement pursuant to a "safe harbor" established by FERC. Such a safe harbor OATT is also known as a reciprocity tariff.

In December 1999, FERC issued Order No. 2000 which was a further measure in FERC's attempt to foster competition in wholesale power markets by encouraging all transmission-owning utilities, including municipal utilities, electric cooperatives and other non-public utilities, to join Regional Transmission Organizations ("RTOs"), which are organizations that regulate and manage the flow of electricity over a region's transmission system to provide equal access to such transmission system for all power generators and to avoid system failure due to system overload. An RTO is to be operated independently of generation interests, and is to be responsible for, among other things, short-term reliability, regional planning and market monitoring. On September 17, 2020, FERC issued Order No. 2222 requiring RTOs to permit distributed energy aggregators to participate in capacity, energy, and ancillary service markets operated by RTOs or Independent System Operators ("ISOs"). To date, no RTO has been formed that encompasses within its territory the service area of any of the Power Purchasers. The CAISO (as defined below), is an ISO and serves some of the functions of an RTO within the State of California. See "California Electric Energy Actions – *California Independent System Operator*" below. Further, there has been increased traction in the Western interconnect to implement an RTO, with both Colorado and Nevada requiring RTO adoption by 2030.

On February 16, 2007, FERC issued Order No. 890 amending the regulations and the pro forma OATT adopted under Order Nos. 888 and 889. Such amendments were adopted to correct certain deficiencies FERC perceived in such regulations and the pro forma OATT and better ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. Order No. 890 was designed to: (i) strengthen the pro forma OATT so that it achieves its original purpose of remedying undue discrimination; (ii) provide greater specificity to reduce opportunities for undue discrimination; (iii) better facilitate FERC's enforcement ability; and (iv) increase transparency in the rules applicable to planning and use of the national transmission system.

On July 21, 2011, FERC issued Order No. 1000 amending Order No. 890 and adopting additional regulations addressing transmission planning and cost allocations for public utilities. Order No. 1000 (as affirmed by FERC in 2012) requires (i) regional planning for all new transmission capacity, including the development of a regional transmission plan by the public utilities in a region, (ii) coordination among public utilities across neighboring transmission planning regions, and (iii) the allocation of cost of new transmission capacity developed through regional or interregional planning efforts to the beneficiaries of such capacity. Order No. 1000 required providers of transmission services to file, for FERC's evaluation, proposed revisions to their respective OATTs to reflect the changes effected by the orders.

In affirming Order No. 1000, FERC noted that certain non-public utilities have elected to satisfy the Reciprocity Requirement by adopting a reciprocity tariff. Based on FERC's finding that non-public utilities have participated in regional planning and FERC's expectation that such participation would continue, FERC declined, however, to assert jurisdiction over non-public utilities under Section 211A of the FPA (added to the FPA by the Energy Policy Act of 2005 discussed below), thus declining to require such utilities to comply with Order No. 1000.

Because the Agency has not purchased any transmission capacity or services from a public utility and does not believe that FERC has otherwise elected to require non-public utilities to comply with FERC's open-access requirements, the Agency does not believe that the Reciprocity Requirement or other open-access requirements apply to the Project. Consistent with the Agency's view, the Agency has not adopted a reciprocity tariff or complied in certain respects with FERC's open-access requirements, including participation in regional planning of transmission. See "*– FERC Transmission Reliability Initiative*" below.

The Agency has adopted, however, an interconnection procedure and has prepared a standard interconnection agreement template to help it evaluate future interconnection requests. The interconnection procedure provides for the Agency to review a new interconnection request on its merits and to permit interconnection only if such request is not detrimental to the Agency or the Project and certain other specific requirements are met or if required by applicable law. Pursuant to the Agency's interconnection procedure, the Agency has granted interconnection rights as described below and in "PROJECT OPERATIONS – Interconnections to the Project" below.

Pursuant to a request made by Milford Wind Corridor Phase I, LLC ("Milford Wind I") that was purported to have been made under certain of the FERC orders and regulations discussed above, the Agency has granted rights to Milford Wind I to permanently interconnect, by way of transmission facilities developed by Milford Wind I, its wind turbine generation project (the "Milford Wind I Project") located near Milford, Utah, to the Agency's transmission system at the Switchyard. See "PROJECT OPERATIONS – Interconnections to the Project" below.

The Agency did not believe it was bound under then-current law to grant Milford Wind I's request. The Agency believed that the Reciprocity Requirement did not apply in the Milford Wind I case because the Agency had not purchased or requested transmission services from Milford Wind I and, therefore, Milford Wind I was not entitled to request transmission services from the Agency under the Reciprocity Requirement. The Agency further believed that FERC did not have the jurisdiction to order the Agency to allow the requested interconnection.

The Agency nevertheless granted such request for the following reasons, among others: (i) the Agency expected the interconnection to benefit certain of the California Purchasers who have purchased, and may purchase additional, entitlements to generation capacity of the Milford Wind I Project; (ii) the Agency anticipated the interconnection might benefit the Project in certain ways, including by making available a possible additional source of "black-start" electric energy; (iii) Milford Wind I was willing to agree to certain terms and conditions, including a condition that it continuously maintain in force a letter of credit to secure its obligations to the Agency with respect to its interconnection to the Switchyard, that minimize financial and operational risk to the Agency and the Project resulting from such interconnection;

and (iv) the Agency wished to avoid a possible challenge to FERC by Milford Wind I if it denied Milford Wind I's interconnection request. It wished to avoid such a challenge because of the cost and time commitment that would be required to defend against it and the possibility that FERC might have interpreted existing law expansively to uphold Milford Wind I's request. Such risks were considered unacceptable by the Agency inasmuch as it did not view the Milford Wind I interconnection, under the terms and conditions to which Milford Wind I had agreed, as having any material adverse impact on the Project and viewed it as providing possible benefits to the Project, as mentioned above.

The Agency has consented to Milford Wind I's assignment of a portion of Milford Wind I's original interconnection entitlement to Milford Wind Corridor Phase II, LLC ("Milford Wind II") with respect to an additional wind turbine project located near Milford, Utah (the "Milford Wind II Project" and together with the Milford Wind I Project, the "Milford Wind Projects").

FERC issued Order No. 842 on February 15, 2018 and Order No. 845 on April 19, 2018, which create additional requirements for pro forma generator interconnection agreements. First, Order No. 842 requires both newly interconnecting generating facilities and existing generating facilities that take an action requiring a new interconnection agreement to ensure controls capable of providing primary frequency response. Next, Order No. 845 (and Order No. 845-A issued February 21, 2019) reforms generator interconnection procedures and agreements to enhance transparency and timeliness for potential generation projects. Because the Agency is not a utility for purposes of such orders, it is not required to comply with these orders but may choose to mirror them in its interconnection agreements.

Most recently, FERC initiated an advanced rulemaking on July 15, 2021, requesting comment on a more holistic process for transmission planning, cost allocation, and generator interconnection. FERC recognized that generators are moving further away from population centers, placing higher demand on transmission facilities. FERC's goal is to explore revised rules that facilitate efficient, regional planning of transmission and system upgrades. As of the date of this Official Statement, FERC still is collecting comments and has not issued a formal notice of proposed rulemaking. It is possible that any rules promulgated pursuant to this rulemaking may impact the Agency and its planning processes.

Energy Policy Act of 2005. On August 8, 2005, the Energy Policy Act of 2005, an amendment to the FPA, was signed into law. The Energy Policy Act of 2005 was intended to establish a comprehensive, long-range energy policy. It provided incentives for traditional energy production as well as newer, more efficient energy technologies and conservation. The Energy Policy Act of 2005 provided for, among other things: (i) the repeal of the Public Utility Holding Company Act ("PUHCA"), *provided, however*, the Energy Policy Act of 2005 transferred some of the existing responsibilities of the SEC under PUHCA to FERC and state regulatory commissions; (ii) a grant to FERC of authority to site transmission facilities within certain congested transmission corridors if states are unwilling or unable to approve siting; (iii) a directive to FERC to permit incentive rate policies as a means to encourage transmission expansion; (iv) revisions to the Public Utility Regulatory Policies Act; (v) the establishment of service obligation protections for native load customers of utilities in certain areas of the country; (vi) the creation of limited FERC jurisdiction over interstate transmission assets of municipal utilities, cooperatives and federal utilities, to permit FERC to order those entities to provide transmission services on rates and terms comparable to those that the entities charge and provide to themselves (as provided in Section 211A of the FPA); (vii) the establishment of mandatory electric reliability rules for all market participants and the creation of a self-regulatory reliability organization, subject to oversight by FERC; and (viii) the provision of certain tax incentives to encourage expansion of transmission facilities and improvement of environmental standards. As directed by the Energy Policy Act of 2005, FERC has adopted many of the applicable implementing regulations.

FERC Transmission Reliability Initiative. On July 20, 2006, FERC approved the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization under Section 215 of the FPA. On March 16, 2007, FERC issued Order No. 693 pursuant to Section 215 of the FPA, adopting a

Notice of Proposed Rulemaking adopting 83 reliability standards that had been developed by NERC. Since then, FERC has continued to adopt and clarify reliability standards (the "Reliability Standards").

Order No. 693 provides that the Reliability Standards apply to all users, owners and operators of the bulk electric system (the "BES") within the United States (other than Alaska and Hawaii). On November 18, 2010, FERC issued Order No. 743 to revise the definition of the BES to include owners and operators of all transmission facilities with a rating of 100 kV or above.

On March 5, 2013, FERC's Order No. 773, a final rule revising the definition of the BES, became effective. FERC noted that the rule is necessary to establish uniformity in how the Reliability Standards would apply to transmission facilities across the various regions of the United States. The final BES rule establishes a "bright line" threshold that includes all facilities operated at or above 100 kV in the BES (subject to certain exclusions for certain facility configurations). The final BES rule also establishes a process for facilities to be reviewed on a case-by-case basis to determine whether the facilities have been improperly classified as part of the BES. The Agency understands from the Operating Agent that the Project complies with the Reliability Standards applicable to the Project with the exception of certain matters that have been self-reported to Western Electricity Coordinating Council. The Agency does not anticipate, however, that such matters will have any material impact on the operation of the Project or the financial condition of the Agency.

FERC Reporting Initiative. On September 21, 2012, FERC issued Order No. 768 pursuant to Section 220 of the FPA, approving final rules that require market participants to report power and transmission sales transaction data to FERC in the form of Electric Quarterly Reports (the "Reporting Requirements"). Order No. 768 expressly applies to non-public utilities (such as the Agency). While acknowledging that Section 205 of the FPA limits FERC's jurisdiction with respect to non-public utilities, FERC interpreted Section 220 of the FPA to extend to non-public utilities.

Order No. 768 exempts from the Reporting Requirements those non-public utilities that have engaged in annual transactions that amount to less than the de minimis market presence threshold established by FERC. Although the Agency's wholesale sales appear to exceed the de minimis amount established by FERC, on July 24, 2014, in response to a petition filed on behalf of the Agency, FERC issued its order stating that the Agency is not required to comply with the Reporting Requirements. FERC based its order on the understanding that the Agency's sale of 100% of the Project's generation output to the Power Purchasers pursuant to the Power Sales Contracts is at cost without being influenced by the wholesale market to determine either pricing or volumes sold.

Access to Interconnection Customer's Interconnection Facilities. On March 19, 2015, FERC issued Order No. 807, establishing a blanket waiver for Interconnection Customer's Interconnection Facilities ("ICIF") from the Open Access Transmission Tariff requirements of 18 C.F.R. 35.28, the Open Access Same-Time Information System requirements of 18 C.F.R. 37, and the Standards of Conduct requirements of 18 C.F.R. 358. Under Order No. 807, those seeking interconnection and transmission service over ICIF subject to the blanket waiver may follow procedures applicable to requests for interconnection and transmission service under Sections 210, 211, and 212 of the FPA, which allows the contractual flexibility for entities to reach mutually agreeable access solutions. Although Order No. 807 does not apply to the Project directly, it may apply to the ICIF owned and used by other generators to interconnect with the Project's transmission system. In turn, this could increase the number of generators seeking transmission service on the Project's transmission system.

With the exception of the Reciprocity Requirement, the Reliability Standards and the Reporting Requirements, the orders discussed above have targeted public utilities rather than non-public utilities. The Energy Policy Act of 1992 and the Energy Policy Act of 2005 and the orders promulgated under those acts evidence, however, an increasing legislative and regulatory intent to extend FERC's jurisdiction over non-public utilities. In addition, legislation has been introduced in past sessions of the United States Congress

that would have brought the Agency and the Power Purchasers completely under FERC jurisdiction had such laws been enacted. It is possible that similar legislation will be introduced and passed in the current or future sessions of Congress.

Even without additional legislation, FERC may elect to rely on existing provisions of the FPA as the basis for extending its jurisdiction over non-public utilities, as it has done pursuant to Section 220 of the FPA or has indicated that it could do pursuant to Section 211A of the FPA. If the Agency or the Power Purchasers are at some future time subjected generally to FERC jurisdiction, the full panoply of FERC orders issued both before and after that time could apply to them.

Despite the uncertainty of the limits of FERC's authority to regulate municipal utilities, such as the Agency, the Agency intends to comply with the FPA and FERC's rules to the extent that they are applicable to municipal utilities similarly situated to the Agency. The FPA and such regulations could have a significant impact, beyond what is discussed above, on the Agency, the Project and the Power Purchasers. For example, under Order No. 888, wholesale customers of the Power Purchasers may have substantially greater access to alternative power supplies which could reduce their demand for power generated at the Project. The Agency does not believe, however, that such compliance will prevent or significantly impair it from operating the Project and conducting its business in substantially the same manner as it is currently doing.

The Agency has not conducted a comprehensive review of how the FPA or FERC's orders may apply to or affect the Agency, the Project or the Power Purchasers directly or indirectly under possible scenarios that may arise in the future. Consequently, except as mentioned above, the Agency is not able to predict the effects that such legislation or regulations will have on the Agency, the Project or the Power Purchasers.

California Electric Energy Actions

Developments in California energy markets to promote energy efficiency, promote competition among electric utilities, mitigate risks, and advance other policy objectives have changed the regulatory climate. For a discussion of these see "The Department of Water and Power of the City of Los Angeles" in APPENDIX E hereto, and "The City of Anaheim Electric System" in APPENDIX F hereto.

Notwithstanding the foregoing developments in California policy and regulation, as of the date of this Official Statement, both the Power Sales Contracts and the Renewal Power Sales Contracts of the California Purchasers continue to be in effect and the Agency does not anticipate any request to modify the Power Sales Contracts or the Renewal Power Sales Contracts in any manner that would impair such Power Sales Contracts or Renewal Power Sales Contracts as security for the 2022 Series A and B Bonds. Furthermore, the Department's 2017 Strategic Long-Term Resource Plan (the plan into which the Department's Power Integrated Resource Plan was expanded starting in 2017) affirms that the Power Sales Contracts are "take-or-pay" contracts with which the Department must comply at risk of "monetary/legal" penalties. The next Strategic Long-Term Resource Plan of the Department is still under development. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Power Sales Contracts" and "– Generation Renewal Project" above.

Utah Electric Energy Actions

Utah Governor Spencer Cox has maintained Utah's historic all-of-the-above approach to responsible energy development. The Agency expects this policy to continue for the foreseeable future. This approach is consistent with H.B. 338, which became law on July 1, 2021 and codifies that the energy policy of the state must promote "adequate, reliable, affordable, sustainable, and clean energy resources." To do so, H.B. 388 does not favor any resource type, requiring consideration of all resources. The Utah Office of Energy Development intends to prepare during 2022 a "State Energy and Innovation Plan" for

public comment that, once finalized, can be used as a guide in decision-making to encourage investment in a diverse portfolio of energy solutions to ensure adequate, reliable, affordable, sustainable, and clean energy resources to power Utah's future.

On the other hand, Utah enacted The Energy Resource and Carbon Emissions Reduction Initiative (S.B. 202) in March 2008, which is a renewable portfolio standard that requires all investor-owned utilities, municipal utilities, and cooperative utilities to pursue renewable energy when it is cost-effective. Each utility has a goal for 20% of its adjusted retail electricity sales to be generated from qualifying renewable sources by 2025. While this renewable goal does not apply to the Project, it may impact the Utah Purchasers' determinations to take power from the Project.

Other Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors discussed above, such factors include, among others:

- effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements in addition to those described herein;
- changes resulting from conservation and demand-side management programs on the timing and use of electric energy;
- effects resulting from future changes in national energy policy or the manner in which such policy is implemented;
- effects of competition from other electric utilities (including increased competition resulting 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;
- other legislative changes, voter initiatives, referenda and statewide propositions, including those directed at limiting or restricting emissions of CO_2 and other GHGs, including the future of EPA's regulation of GHG emissions from power plants;
- national, state and local initiatives or policies that favor "renewable" or "green" electric generation methods over generation facilities powered by fossil fuels;
- substantial public sentiment against the use of coal as a fuel for electric generating facilities;
- increased competition from independent power producers and marketers, brokers and federal power marketing agencies;
- "self-generation" or "distributed generation" (such as microturbines, fuel cells and solar installations) by industrial and commercial consumers and others;
- issues relating to the ability to issue tax-exempt obligations to finance or refinance electric generation or transmission facilities, 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;
- effects of inflation on the operating and maintenance costs of an electric utility and its facilities;
- future changes in load requirements;
- increases in costs and uncertain availability of capital;

- 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;
- unavailability of or substantial increases in the cost of coal or natural gas used as fuel for generation facilities;
- inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity;
- issues relating to the reliability of electric transmission systems and grids, such as the reliability issues highlighted or exposed by power blackouts that have occurred in widespread regions of North America at various times;
- availability and sufficiency of transmission capacity, particularly during times of high demand;
- effects of changes in the economy; and
- effects of possible manipulation of electric markets.

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 Agency cannot predict what effects such factors will have on the business, operations and financial condition of the Agency, the Project or the Power Purchasers, but the effects could be significant.

ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

General

Electric utilities are subject to extensive governmental requirements with respect to the siting and licensing of facilities, safety and security, air and water quality, land use, hazardous and solid waste, and other environmental factors. The coal-fired electrical generating industry also is experiencing increased scrutiny from EPA and some sectors of the public regarding various environmental issues, including climate change. EPA Administrator Michael Regan, for example, stated that EPA will rely on a suite of environmental regulations to push investment away from coal-fired electrical generation. Indeed, federal, state and local environmental standards are subject to changes arising from legislative, regulatory and judicial action. Consequently, although the Agency believes that the Project currently complies with all applicable environmental regulations, there can be no assurance that the Project will remain subject to the regulations currently in effect or in compliance with future regulations, or will be able to retain the current conditions in all required operating permits. Evolving environmental standards could result in additional capital or operating expenditures, reduced operating levels or the complete shutdown of individual EGUs.

The Agency cannot predict what impact climate change regulation, environmental regulations and concerns regarding electric and magnetic fields might have on the business, operations and financial condition of the Agency, the Project or the Power Purchasers, but their influence could be significant. The following briefly discusses how some of these factors specific to Utah, its regulatory climate, and the Project might affect the present and future operation and financial condition of the Project. This discussion, however, is neither comprehensive nor definitive and the following matters are subject to change. For a general discussion of federal Environmental and Health Factors Affecting the Electric Utility Industry, see "The Department of Water and Power of the City of Los Angeles" in APPENDIX E hereto, and "The City of Anaheim Electric System" in APPENDIX F hereto.

Air Emissions

Congressional action related to air emissions has a significant impact on the electric utility industry. The federal Clean Air Act ("CAA"), for example, requires EPA to set National Ambient Air Quality Standards ("NAAQS") for six common pollutants considered harmful to public health and the environment, which are called criteria pollutants. The criteria pollutants that are regulated under the permit under which the Project operates are sulfur dioxide ("SO_2"), ozone, nitrogen oxide ("NOx"), coarse and fine particulate matter (respectively, "PM_{10}" and "$PM_{2.5}$"), and carbon monoxide ("CO"). In 1990, Congress amended the CAA (the "1990 Amendments") to substantially revise a number of CAA provisions, including those aimed at improving ambient air quality throughout the United States and regulating hazardous air pollutant emissions from specific source categories, including EGUs. A key feature of the 1990 Amendments applicable to the Project is the reduction of sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") emissions from electric utility power plants fueled by oil and coal.

The State of Utah's air quality laws and regulations, including State Implementation Plans ("SIPs") adopted by the State and approved by EPA, also regulate the operation of the Project and its air emissions. Along with the requirements of the Utah Air Conservation Act and accompanying rules, the State administers the CAA programs applicable to the Project through the applicable SIP and delegation of other authorities by EPA.

Title V Permitting. The Agency is required to comply with provisions of the 1990 Amendments that require the Project to: (i) obtain an operating permit (or Title V permit) every five years; and (ii) pay an annual fee based on its emission of regulated pollutants. The Project's Title V permit incorporates all air quality requirements applicable to the Project and requires monitoring and reporting of emissions. The Project's current operating permit was last renewed on September 12, 2018 and will expire on September 12, 2023. The recent renewal of the permit did not require any material changes in the overall operation of the Project. The Agency plans to file an application to revise the permit in a timely manner based on planned changes at the Project.

New Source Review. The CAA, as implemented by the State, also contains a pre-construction permitting program for new or modified emissions sources, titled the New Source Review ("NSR") program. Generally speaking, NSR laws and regulations cover: (i) the construction of new major sources of air pollution emissions; and (ii) modifications to existing facilities that result in a significant increase in emissions of criteria pollutants. The NSR regulations generally require emission sources to obtain a Prevention of Significant Deterioration ("PSD") permit before constructing new plants or making major modifications to existing plants in attainment areas (as defined below) such as the area in which the Intermountain Generating Station is located. See "– National Ambient Air Quality Standards" below. Routine maintenance, repairs and replacements are generally excluded from the NSR regulations. On November 24, 2020, EPA published a rule providing that emissions increases as well as decreases can be considered in determining whether a proposed physical or operational change would result in a "significant net emissions increase" as the first step of the two-part test to determine whether a major modification will trigger PSD permitting. The final rule went into effect on December 24, 2020. The State has adopted the federal NSR regulations, including those that have survived judicial challenge.

PSD permits are to be issued only if the new plant or major modification includes emissions limits and/or pollution control measures that reflect the best available control technology ("BACT") and if the emissions will not increase ambient air pollution beyond certain specified limits. The NSR regulations directly impact an electrical utility's operations because they may affect the repair, replacement or upgrade of boilers and production equipment and, if triggered, may result in lengthy NSR permitting, costly new pollution controls, and challenges to the permitting action by third parties. The Agency believes the Project can continue to operate under the current state and federal NSR regulations.

New Source Performance Standards. The New Source Performance Standards (the "NSPS"), 40 CFR Part 60 Subpart Da and 40 CFR Part 64, apply to the two EGUs at the Intermountain Generating Station. Since completion of the Intermountain Generating Station, EPA has amended the NSPS at various times. These amendments apply to new, reconstructed or modified steam EGUs. The Agency cannot assess the specific effect of these amendments on the Project until a specific modification is being considered that would result in the Project having a new, reconstructed or modified unit. See also "– Federal Regulation of Greenhouse Gases – New Source Performance Standards Rule for Greenhouse Gases" below.

National Ambient Air Quality Standards. The CAA requires EPA to establish NAAQS for certain common air pollutants. When EPA establishes a NAAQS, each state must identify each area within its boundaries that does not meet one or more NAAQS (known as a "non-attainment area") and develop regulatory measures in its SIP to reduce or control the emissions of the air pollutants in order to become an area that meets the NAAQS (known as an "attainment area"). When an area is designated as a non-attainment area, stricter restrictions on the emissions of the air pollutants exceeding the NAAQS are imposed, and it can be more difficult and costly to obtain permits for new major sources or major modifications to existing sources. The following sections discuss the potential impacts on the Project of NAAQS for SO_2, NOx, PM_{10}, $PM_{2.5}$, ozone and CO.

SO_2 Emissions. In a letter dated November 1, 2016 to EPA Region 8 Air Program Director Carl Daly, Utah Governor Gary Herbert recommended that all counties in Utah, including Millard County, be designated as "attainment" for the 2010 primary SO_2 NAAQS. On January 9, 2018, EPA published a final rule designating all counties in Utah as "Attainment/Unclassifiable" for SO_2. On February 26, 2019, EPA announced its final decision to retain without changes the primary SO_2 NAAQS.

NOx Emissions. EPA also has issued regulations implementing the NOx provisions of the CAA. These regulations mandate lower NOx emission limits for wall-fired boilers (such as those of the Project) and tangentially-fired boilers. According to the Operating Agent, the Project complies with the revised lower limits for NOx.

With respect to nitrogen dioxide ("NO2") emissions, on February 9, 2010, EPA published revisions strengthening the health-based NAAQS. EPA set a new one-hour NO2 standard at the level of 100 ppb. EPA's NAAQS for NO2 are designed to protect against exposure to the entire group of nitrogen oxides. The entire State has been designated by EPA as "unclassifiable/attainment" with respect to NO2 NAAQS.

PM_{10} and $PM_{2.5}$ Emissions. The CAA also regulates the emission of particulate matter in two forms. The PM_{10} Standard regulates inhalable coarse particles, which are smaller than 10 micrometers and larger than 2.5 micrometers. The $PM_{2.5}$ Standard regulates particles less than 2.5 microns in diameter. The Project's air permits contain PM limits and the Project is in material compliance with those limits.

All or portions of counties along the Wasatch Front and Cache County were designated as nonattainment for the 2006 24-hour $PM_{2.5}$ NAAQS. The Utah Division of Air Quality developed a $PM_{2.5}$ SIP to submit to EPA containing control measures that come into compliance with the $PM_{2.5}$ NAAQS. The SIP was approved by the Utah Board of Air Quality and submitted to EPA in early 2019. On November 6, 2020, EPA issued a proposed rule to re-designate the Provo and Salt Lake City areas from nonattainment to attainment for $PM_{2.5}$ and approve various related SIP submissions. Millard County, the county in which the Project is located, is not currently designated as a $PM_{2.5}$ non-attainment area, with the result that $PM_{2.5}$ SIP should not include any measures that affect the Project.

On December 7, 2020, EPA announced its final decision to retain, without revision, the existing primary and secondary NAAQS for both PM_{10} and $PM_{2.5}$. On June 10, 2021, however, EPA announced it would reconsider EPA's prior decision to retain the particulate matter NAAQS. To date, EPA has not announced a proposed revised rule; however, EPA's Clean Air Scientific Advisory Committee recommended in March 2022 that the EPA Administrator tighten the annual and daily limits of $PM_{2.5}$.

At this time, the Agency cannot predict the impact on the Project of any changes to the PM NAAQS, modifications to the SIP, any future revisions to the current Utah $PM_{2.5}$ related regulations, or any new Utah $PM_{2.5}$ regulations.

***Ozone*.** Ozone is not emitted by the Project; rather it results from the interactions among NOx, volatile organic compounds, sunlight, moisture and temperature in the ambient atmosphere. Control of ambient ozone is a function of limitations on emissions of NOx and other ozone precursors. On October 26, 2015, EPA published a final rule lowering both the primary and secondary ozone NAAQS from 75 ppb to 70 ppb. On December 23, 2020, EPA completed its review of the full body of currently available scientific evidence and exposure/risk information and announced its final decision that it would retain, without revision, the existing ozone NAAQS. However, on November 1, 2021, EPA announced it would reconsider the 2020 decision to retain 2015 standards, based on the existing scientific record; EPA is currently targeting the end of 2023 to complete this reconsideration.

On October 26, 2015, EPA published a final rule lowering both the primary and secondary ozone NAAQS from 75 ppb to 70 ppb. On June 4, 2018, EPA published the air quality designations for the ozone NAAQS. On August 14, 2020, EPA proposed to retain the current ozone NAAQS without revision. On December 23, 2020, EPA completed its review of the full body of currently available scientific evidence and exposure/risk information and announced its final decision that it would retain, without revision, the existing ozone NAAQS. However, on November 1, 2021, EPA announced it would reconsider the 2020 decision to retain 2015 standards, based on the existing scientific record; EPA is currently targeting the end of 2023 to complete this reconsideration.

Portions of the Uinta Basin and the Wasatch Front are designated as "Marginal Nonattainment," but all other counties in the State, including Millard County, are designated as "Attainment/Unclassifiable" with the 2015 standard. As long as the Uinta Basin and Wasatch Front remain in Marginal Nonattainment, a nonattainment SIP is not required to be developed and submitted to EPA. The Agency, however, cannot predict the impact on the Project of any future action with respect to the ozone NAAQS.

On April 6, 2022, EPA issued a proposed rule under its "good neighbor" or "interstate transport" authority pursuant to the Clean Air Act. 87 Fed. Reg. 20036 (Apr. 6, 2022). Specifically, EPA is proposing a finding that interstate transport of ozone precursor emission from 26 upwind states, including Utah, is significantly contributing to or interfering with downwind states' compliance with the 2015 ozone NAAQS. As a result, EPA is proposing Federal Implementation Plan requirements for these states as well as new ozone season NOx emission budgets and reductions in 2023 for fossil fuel-fired power plants. This proposal could have an impact on the Project if the rule is finalized in the future, but the Agency cannot predict the extent of such impact at this time.

CO Emissions. On August 31, 2011, EPA published a final rule concluding that the primary CO NAAQS should be retained and that no secondary NAAQS should be set for CO. Millard County, where the Intermountain Generating Station is situated, is an attainment area with respect to the primary CO NAAQS. The Project complies with applicable limits on CO emissions.

***Mercury Emissions*.** The maximum achievable control technology standards rule for mercury emissions (the "MATS Rule") was published in the Federal Register on February 16, 2012, and is the latest step in a process to evaluate and regulate mercury emissions from coal-fired electric generating plants, which is mandated by the 1990 Amendments. The MATS Rule sets mercury and air toxics standards ("MATS") for emissions from coal- and oil-fired power plants. On June 29, 2015, the U.S. Supreme Court remanded a lawsuit challenging the MATS Rule to the D.C. Circuit to address EPA's failure to consider costs when deciding whether to regulate the source category under the hazardous air pollutant provisions of Section 112 of the CAA. The D.C. Circuit remanded the rule to EPA to conduct a cost assessment but without vacatur, allowing the rule to remain in effect until revised by EPA. EPA has issued a variety of rulemakings since the 2015 Supreme Court decision, and in February 2022 EPA proposed to re-institute a

2016 determination (reversed in 2020) that the consideration of cost does not alter EPA's original conclusion that it is "appropriate and necessary" to regulate hazardous air pollutant emissions from EGUs. None of these rulemakings changed the under lying MATS standards.

Performance testing has been conducted with respect to the Project consistent with current MATS requirements. The testing has demonstrated compliance with the current MATS emissions limits. Compliance with the MATS Rule is expected to have ongoing financial impacts. The Operating Agent reports it is continuing to evaluate those financial impacts to the Project and, as a result, the Agency does not yet know the full impact of the MATS Rule on the Project.

In the midst of the uncertainty with respect to federal regulation of mercury emissions, on March 14, 2007, the Utah Air Quality Board adopted a "Designated Facilities Plan to address Mercury Emissions at Coal-Fired EGUs." This plan includes a state-only rule that establishes minimum performance criteria for existing EGUs and requires that potential increases in mercury emissions from new or modified EGUs be offset (at a ratio of 1:1.1) by contemporaneous reductions of mercury emissions. The State's minimum performance criteria include a rule that by December 31, 2012, coal-fired power plants were to have met a mercury emissions limit of 6.5×10^{-7} lb/mmbtu or to have had at least a 90% mercury removal efficiency.

In the fall of 2011, the Agency committed, at the State's request, to perform quarterly stack tests to ensure that the Project is operating in compliance with the mercury emissions limit. With the agreement of the State, the stack tests are now performed on an annual basis. The Agency has timely completed each stack test, and, in each instance, the results have confirmed that the Project is in compliance with the Utah mercury emissions limit.

Acid Rain. Under Title IV of the 1990 Amendments (known as the "Acid Rain Program"), SO_2 emission reductions from fossil-fueled electric generation facilities are to be achieved through a cap-and-trade program for SO_2 allowances. The Project is covered by the Acid Rain Program and is subject to its restrictions. The 1990 Amendments contain provisions for allocating annual allowances to power plants based on historical or calculated levels under a cap. An "allowance" is defined as the authorization to emit one ton of SO_2 during a given year, which may also be used for compliance in a future year. EPA has allocated allowances to specific generating units, including each unit of the Intermountain Generating Station. At the end of each year, the source must hold an amount of allowances at least equal to its annual emissions.

The Operating Agent expects, based on analyses of the Intermountain Generating Station's SO_2 emissions to date and the allowances currently allocated to the Project, to be able to operate the Intermountain Generating Station at projected plant capacity factors in compliance with the Acid Rain Program in the future. The Operating Agent believes that there will not be significant operating, maintenance or capital expenditures required for the Project to meet the requirements of the Acid Rain Program.

***Regional Haze*.** EPA adopted its "Regional Haze Rule" in 1999 in an effort to reduce haze at Class I federal areas, such as national parks and wilderness areas. Currently, there are five regional planning organizations in the United States which address regional haze and related issues. These organizations evaluate technical information to better understand how their states impact Class I areas across the country, and develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze. The regional organization in which Utah participates is the Western Regional Air Partnership ("WRAP"), which is a collaborative effort of tribal governments, state governments and various federal agencies that work to implement the recommendations of the CAA's Grand Canyon Visibility Transport Commission (the "GCVTC") and to develop the technical and policy tools needed by western states to comply with EPA's regional haze regulations.

On July 5, 2016, EPA published a supplement to its 2012 rule. The supplement partially approved and partially disapproved a supplement to the State's Regional Haze SIP. Neither the supplement submitted by the State to EPA nor EPA's supplemental rule partially approving and partially disapproving the SIP relate to the Project.

The State is currently developing the State's Regional Haze SIP for the Second Implementation Period, which covers the years 2018 through 2028. On April 6, 2022, the Utah Air Quality Board proposed for public comment the Regional Haze SIP for the Second Implementation Period. As proposed, the SIP establishes an enforceable closure date of no later than December 31, 2027 for the Project's coal-fired units. The State rejected calls to require control upgrades for SO_2 during the interim period. The Agency cannot predict the scope of the final SIP and whether additional controls will be required that could have an impact on the Project.

Section 114 Information Requests. Under Section 114 of the CAA, EPA has the authority to request from any person who owns or operates an emission source, information and records about operation, maintenance, emissions, and other data relating to such source for the purpose of developing regulatory programs, determining if a violation of the CAA has occurred, or carrying out other statutory responsibilities. If such violations are found to have occurred, EPA or other enforcement authorities could require the installation of new pollution control equipment in addition to modifications that have already been completed or planned and could require the payment of fines and penalties.

On September 28, 2010, EPA sent a letter to the Agency and IPSC requesting information with respect to the Project pursuant to Section 114(a) of the CAA. The request for information indicated that the purpose of the request was to determine whether the Agency has complied with the CAA, but the letter did not allege any specific violations. The Agency and IPSC responded in a timely manner to that request and follow-up requests for information.

The Agency understands that the requests under Section 114 of the CAA are part of a national enforcement initiative undertaken by EPA against owners and operators of electric generating facilities. The initiative generally involves EPA asserting that facilities have failed to comply with the NSR regulations implicated by physical or operational changes at such facilities.

With respect to the Agency, EPA asserts that certain uprate projects undertaken at the Generating Station during the period from 2002 to 2004 triggered the obligation to comply with the regulatory requirements of the NSR program. On February 19, 2015, the Sierra Club sent the Agency and IPSC a formal notice of intent to sue under the citizen suit provisions of the CAA, alleging violations of the NSR provisions of the CAA. The Agency and IPSC have responded to the allegations made in the Sierra Club's notice letter. However, no formal action has been initiated against the Agency or IPSC by the Sierra Club.

Representatives of EPA, the U.S. Department of Justice ("DOJ") and the Agency have met from time to time to discuss the information provided and EPA's conclusions based on that information. Discussions regarding settlement of potential claims related to EPA's inquiries began in 2014 and are continuing. In connection with EPA's inquiries, EPA and the Agency entered into an agreement that provides for the tolling of any applicable statute of limitations that may apply to matters that EPA may pursue arising out of EPA's inquiries. The term of the tolling agreement had previously been extended to December 31, 2018. Although, customarily at EPA's request, EPA and the Agency have extended the tolling agreement on several prior occasions, EPA has not proposed a further extension as of the date of this Official Statement. The Agency cannot predict at this juncture what action EPA may take in the future or the impact of EPA's failure to extend the tolling agreement on its ability to seek legal remedies.

Air Quality Summary. The Project is designed and operated to meet the requirements of federal and state air quality laws. The boilers have been designed and constructed to meet stringent regulatory emission limits for NOx. The flue-gas desulfurization equipment (scrubber) for each generating unit at the

Project consists of a wet scrubber system designed and constructed to remove 90% of all SO_2. The baghouse for each generating unit at the Project consists of three modular fabric filters designed and constructed to remove at least 99.75% of all particulate material. In summary, the Agency believes that the Project complies with current requirements under the CAA and the Utah Air Conservation Act. Additionally, the Agency believes that the Intermountain Generating Station currently meets all applicable federal and state air emission regulations and permit requirements. Reports submitted to the Utah Division of Air Quality indicate that the Intermountain Generating Station complies with permissible emissions for all air pollutants.

Regulation of Greenhouse Gases

Federal and California Greenhouse Gas Initiatives. In recent years, the federal government's involvement in GHG emission issues has varied depending on which administration is in office. As discussed further below, EPA is currently monitoring GHG emissions and, as of January 2, 2011, EPA began regulating GHG emissions from certain large sources under the CAA. The Agency cannot predict congressional action on GHG emissions in the current Congress or in future Congresses, nor can the Agency predict action that may be taken by the current or any future presidential administration with respect to the regulation of GHG emissions. For a discussion of federal and California GHG and renewable energy initiatives, see "The Department of Water and Power of the City of Los Angeles" in APPENDIX E hereto, and "The City of Anaheim Electric System" in APPENDIX F hereto.

The Agency will continue to analyze the potential impact of the federal and California GHG initiatives, but the Agency cannot determine, with any certainty at this time, what additional impacts, if any, could result to the Agency or the Power Purchasers from these initiatives and what effects these initiatives may have on the California or Utah electric energy markets or electric energy markets generally. Furthermore, the Agency cannot predict what, if any, effects the federal and California GHG initiatives or future related laws, orders or regulations, including amendments or modifications to the federal or California GHG initiatives, will have on the Agency or the Power Purchasers or the markets in which they operate. As the federal government and its agencies, California and its agencies, including CARB and the CEC, and local governments move forward with regulatory and administrative processes to fully implement the federal and California GHG initiatives, it is likely that the Project and the Power Purchasers will continue to explore all legal options available to them to reduce GHG emissions attributable to their operations, including the divestiture of GHG-emitting assets and the acquisition of additional renewable and non-fossil fueled generation assets. The Agency can neither predict what, if any, such actions the Power Purchasers may take, nor the timing of any such actions that may be taken. It is possible, however, that federal and California GHG initiatives, alone or in combination, could affect the Agency and the Power Purchasers in other ways.

In particular, since 2016, the Department has included the GHG cost factor in its pricing of power from the Project to reflect externalities from coal-fired power generation (the "GHG Cost Factor"). Although the GHG Cost Factor does not represent a monetary cost of the operation of the Project, it is increasing the dispatch cost of power from the Project for the Department. The additional GHG Cost Factor often made the price of the power generated by the Project noncompetitive in comparison to other resources available to the Department and the other California Purchasers. As a result of the GHG Cost Factor among several other factors, including market conditions, system demand, relatively low natural gas prices, and operational constraints caused by a leakage incident at the natural gas storage facility at Aliso Canyon in California, the California Purchasers began substantially decreasing their scheduling of power from the Project in 2016, which trend has continued through 2021 (though drought conditions have resulted in some mitigation to that trend). As long as current conditions persist, the Agency anticipates that scheduling of power will not return to pre-2016 levels. The reduction in scheduling of power has resulted in a substantial decrease in the Project's capacity factor. See "PROJECT OPERATIONS – Management and Operation of the Project" below.

The Power Sales Contracts remain valid, binding and enforceable notwithstanding any such federal or California initiatives or any actions taken in response thereto. It is possible, however, that these initiatives, alone or in combination, could affect the Agency and the Power Purchasers in other ways. For example, they:

(i) may limit or eliminate the ability of the Agency and the Power Purchasers to enter into amendments to the respective Power Sales Contracts between them, including the types of amendments that may be entered into (although the Agency does not believe that the initiatives or actions limited the ability of the Agency or the Power Purchasers to enter into the Power Sales Contracts Amendments);

(ii) could prevent the Agency from selling a defaulting Power Purchaser's generation entitlement share in the Project to another Power Purchaser or other electric utility on a long-term basis or in excess of available allowances and offsets in connection with the exercise by the Agency of its remedies under the applicable Power Sales Contract as the result of such a default, thus potentially impairing the Agency's ability to recover its losses from such a default;

(iii) could prevent a Power Purchaser from entering into future arrangements to resell its electric generation from the Project to another Power Purchaser or other electric utility on a long-term basis or in excess of available allowances and offsets; and

(iv) may restrict the ability of the Power Purchasers to import power generated by the Project pursuant to a Power Sales Contract to the extent the power to be imported exceeds available allowances and offsets.

Utah Greenhouse Gas Initiatives. In February 2022, Utah announced it would be joining three other states, Colorado, New Mexico, and Wyoming, in an effort to coordinate and develop a regional hydrogen hub—anticipated to reduce greenhouse gas emissions in the Mountain West. As part of the agreement signed, the four states will work together to seek a portion of $8 billion allocated in the 2021 Infrastructure Investment and Jobs Act.

Nuisance Liability for Greenhouse Gas Emissions. Several lawsuits have been filed and decided in the past decade that attempted to impose nuisance liability on coal-fired electric generating facilities for GHG emissions. These cases have not directly involved the Project, but the cases are part of a relatively recent resurgence in litigation involving electrical generating facilities, such as the Project, that emit GHGs. There are a number of other cases in various jurisdictions seeking damages and/or injunctive relief from energy companies for the adverse effects of climate change. In particular, nuisance claims involving air-related issues appear to be increasing. While no case related to GHGs has been brought against the Project, these cases illustrate the potential for such claims to be made in the future.

Other Environmental Regulation

Waste Management. There are substantial federal, State and local regulations regarding solid and hazardous waste management, liability for waste disposal, and management of coal combustion residuals ("CCR"). The federal Resource Conservation and Recovery Act ("RCRA") and the Utah Solid and Hazardous Waste Management Act ("SHWMA") require permits from the Utah Department of Environmental Quality for the siting of hazardous waste disposal facilities and receipt, disposal and management of hazardous waste. In addition, RCRA and SHWMA require permits for the siting, receipt, disposal and management of certain types of non-hazardous solid waste.

The Operating Agent has established a waste management plan for the Project. The plan is designed to assure that the Project's present and future operations conform to applicable waste disposal

regulations. The Operating Agent has also assessed Project properties for potential liability arising from past, latent contamination. Subject to the following discussion of CCR, the Operating Agent has indicated that the Project's waste management program complies with all federal, state and local statutes and guidelines and all applicable permit requirements. For additional discussion of waste management issues and CCR, see "The Department of Water and Power of the City of Los Angeles" in APPENDIX E hereto, and "The City of Anaheim Electric System" in APPENDIX F hereto.

In April 2015, EPA promulgated the final coal combustion residuals rule (the "CCR Rule"), which regulates the disposal and management of CCR as non-hazardous under Subtitle D of RCRA. The CCR Rule became effective in October 2015. On September 1, 2016, the State of Utah enacted its state CCR regulations, which are substantially identical to the CCR Rule.

Following litigation challenging the CCR Rule and court decisions vacating and remanding certain provisions, the Rule has been amended to make changes requiring additional demonstrations for continued operation of CCR impoundments. Specifically, the new provisions in 40 CFR § 257.103(f)(2) continue to allow subject facilities a site-specific alternative to initiating closure due to permanent cessation of a coal-fired boiler by a date certain, setting the completion of closure date as no later than October 17, 2028 for surface impoundments larger than 40 acres. In addition, facilities utilizing the new alternative closure provision at § 257.103(f)(2) were required to submit to EPA by November 30, 2020, a risk mitigation demonstration supporting their continued operation of a CCR surface impoundment for EPA review and approval.

The Project utilizes impoundments (ponds) and a landfill for the management of coal ash constituting CCR that is subject to the CCR Rule. The Operating Agent has reported that the Project has met all interim compliance requirements for the CCR Rule including setting up a public website and posting CCR operating records, developing groundwater monitoring wells and sampling plans, sampling of groundwater wells quarterly, developing and implementing a fugitive dust monitoring plan and starting to develop a corrective action plan. Groundwater sampling has shown statistically significant concentrations of certain constituents in monitoring wells surrounding the impoundments. Under the CCR Rule, the impoundments are required to be closed according to prescribed timelines. The Agency has elected a course of action under the CCR Rule that allows for continued acceptance of CCR in the impoundments so long as the coal-fired boilers at the Project will cease operation by a date certain and the impoundments are closed by October 17, 2028.

The Agency already is required pursuant to the Power Sales Contracts to cause the Project to use another fuel source for generation by 2025 and the Agency has already made the determination not to continue operation of the coal-fired boilers at the Project beyond the time when the Project switches to using natural gas. See "PROJECT OPERATIONS – Management and Operation of the Project – *Removal of Coal Units from Service*" below. The Agency filed this initial election on September 12, 2018 under the CCR Rule provisions in effect at that time and has complied with all reporting requirements associated with that election. On November 30, 2020, following EPA's amendment of the CCR Rule, the Agency timely filed the risk mitigation demonstration supporting continued use of the Project impoundments with a completion of closure date no later than October 17, 2028, subject to EPA review and approval. On January 11, 2022, EPA published its determination that the Agency's demonstration was complete; however, as of the date of this Official Statement, EPA has yet to issue a substantive decision on the demonstration. To date, EPA has only published its findings on four other facilities' demonstrations—three were denied and one was conditionally approved.

EPA is also proposing to revise the CCR beneficial use definition and proposing to introduce a single approach to consistently address the potential environmental and human health issues associated with piles of CCR. The Agency does not anticipate that these amendments will have any material impact on the course of action previously required under the CCR Rule. EPA has proposed other amendments to the CCR Rule that the Agency has concluded do not apply to the Project.

The State rule regulating CCR has not been amended to reflect congressional and EPA developments since 2016. However, the Operating Agent applied for a permit under the State's program for operation of the Project's CCR impoundments and landfill. The final permit was issued on November 23, 2020. Notwithstanding regulatory uncertainties, the Project has continued implementing its compliance and closure plans pursuant to the provisions of the CCR Rule and State law governing CCR.

The Agency continues to analyze the impacts of the CCR Rule and state regulation of CCR on the Project, including anticipated costs of compliance. The Agency's total cost of compliance with the final CCR Rule was estimated to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period that commenced in 2019 and is estimated to end between approximately 2025 and 2028 (except for long-term groundwater monitoring, which will last approximately 30 years after closure of the impoundments).

Water Quality. The federal Clean Water Act, the Utah Water Quality Act and the regulations promulgated under those statutes regulate discharges of wastewater, including storm water runoff. The Agency believes the Project has, or has initiated the process to receive, all required water quality related permits and approvals.

While the Project has no surface water discharges off-site, the Project utilizes a cascading process pond system on-site. The Project has been subject to a Groundwater Discharge Permit through the Utah Department of Environmental Quality Division of Water Quality since 2001, which requires the Agency to monitor compliance at wells located adjacent and downgradient to the impoundments and permitted facilities, sets groundwater protection levels, and requires semi-annual reporting. One or more of the on-site impoundments may have leaked in the past into groundwater. The Project has addressed and will continue to address this issue through a remediation and recovery plan approved and regulated by the Utah Department of Environmental Quality, and consistent with its plans developed under the CCR Rules as described previously. Pursuant to the plan, the Agency has installed monitoring wells to monitor groundwater and recovery wells to pump water back into the process pond system and installed more monitoring wells in 2019. The Agency expects to maintain the monitoring and recovery wells, to perform chemical analysis of the well water and to implement further remedial measures as necessary under the groundwater permit and the CCR Rules. The Agency has submitted a renewal application for the Project's Groundwater Discharge Permit (which expired on May 24, 2021, but has been administratively extended given the timely application). The Agency is in discussions with the Division of Water Quality regarding its applications and expects the renewed permit to be issued later in 2022.

Other Environmental Concerns. The Agency's electric operations are subject to continuing environmental regulation. Concerns that may result in additional regulation include electric and magnetic fields. See "The Department of Water and Power of the City Los Angeles" in APPENDIX E hereto.

Federal, state, regional and local standards and procedures that regulate the environmental impact of the Agency, the Project and the Power Purchasers 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 electric facilities in operation or contemplated 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 applicable environmental standards could result in increased costs of electric facilities, reduced operating levels or the complete shutdown of individual EGUs and other facilities not in compliance.

The Agency cannot predict at this time whether any additional legislation, regulations or rules will be enacted that affect the Agency's operations, and if such laws or rules are enacted, what the costs to or impacts on the Agency, the Project or the Power Purchasers might be in the future because of such future enactments.

INTERMOUNTAIN POWER AGENCY

History

The Agency, a separate legal entity and a political subdivision of the State, was organized in June 1977 pursuant to the provisions of the Act and under the Intermountain Power Agency Organization Agreement. Its membership consists of 22 municipalities and one interlocal entity that are suppliers of electric energy in the State. The Agency was created for the purpose of owning, acquiring, constructing, operating and maintaining the Project. The Agency's term of existence will expire on the later of June 30, 2063 and five years following the last to occur of events specified in the Intermountain Power Agency Organization Agreement. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Generation Renewal Project" above.

The Interlocal Cooperation Act

The Act authorizes local governmental units to make the most efficient use of their powers by enabling them to cooperate with other localities on a basis of mutual advantage to provide services or facilities that will best accommodate the needs and development of the local communities. Its purposes also include provision of the benefits of economy of scale, economic development and utilization of natural resources for the overall promotion of the general welfare of the State.

An interlocal entity is formed under the Act when the governing bodies of two or more eligible municipalities of the State determine by resolution that the creation of such an agency is in the best interest of the individual municipalities. An interlocal entity so formed has the authority to undertake and finance the facility or improvement contemplated by its organization agreement, and is a political subdivision of the State with power to, among other things: own, acquire, construct, operate, maintain and repair any facility or improvement set forth in the organization agreement; borrow money or incur indebtedness, issue revenue bonds or notes for the purpose for which it was created; offer, issue and sell warrants, options or other rights relating to its bonds or notes and any rights or interests pertaining to the bonds or notes; assign, pledge or otherwise convey as security for the payment of any such bonded indebtedness, the revenues and receipts from the facility; and sell or contract for the sale of the product or services within or without the State on terms deemed in the best interest of its participants. The Act also permits an interlocal entity to construct facilities to render services in excess of those required to meet the requirements of the members of such agency if it is determined to be necessary to accomplish the purposes of the Act; *provided, however*, that any such excess which is sold shall be sold on terms which assure that the cost of providing the excess will be recovered by such interlocal entity.

As the Agency was preparing for the Generation Renewal Project, the Agency advocated for changes to the Act to permit the Generation Renewal Project to proceed. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Generation Renewal Project" above.

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Membership

The following is a list of the Agency's 23 members and their representatives:

Member	Representative	Member	Representative
Beaver City	Jason Brown	Lehi City	Joel Eves
City of Bountiful	Allen Johnson	City of Logan	Mark Montgomery
City of Enterprise	S. Lee Bracken	Meadow Town	Eric Larsen
Ephraim City	Shaun Kjar	Monroe City	Josey Parsons
City of Fairview	Greg Sorensen	Morgan City	Ty Bailey
Fillmore City	Eric Larsen	Mt. Pleasant City	Shane Ward
Heber Light & Power Company	Jason Norlen	Murray City	Blaine J. Haacke
Holden Town	Eric Larsen	Town of Oak City	Dwight F. Day
City of Hurricane	Scott Hughes	Parowan City	Jeremy Franklin
Hyrum City	Martin Felix	Price City	Nick Tatton
Kanosh Town	Eric Larsen	Spring City	Kent Kummer
Kaysville City	Bruce Rigby		

Upon termination of the Power Sales Contract of a Utah Municipal Purchaser that is not also a Renewal Purchaser, such Utah Municipal Purchaser will cease to be a member of the Agency. Since Meadow Town and Monroe City are not Renewal Purchasers, they will cease to be members of the Agency effective as of the expiration of their Power Sales Contracts which is provided to occur on June 15, 2027.

Organization and Management

The Agency is governed by its seven-member Board of Directors elected by, and from among, the members' representatives, for staggered four-year terms. The present members of the Board of Directors and the offices they hold are as follows:

Name	Office	Term Ends December 31
Blaine J. Haacke	Chair	2023
Nick Tatton	Vice Chair	2023
Eric Larsen	Secretary	2024
Allen Johnson	Treasurer	2024
Joel Eves	Member	2025
Mark Montgomery	Member	2025
Bruce Rigby	Member	2022

The management of the Agency is under the direction of its General Manager, who serves at the pleasure of the Board of Directors. The following are the members of the Agency's management staff and their backgrounds.

Cameron R. Cowan – General Manager. Mr. Cowan assumed the position of General Manager in January 2022. Prior to his appointment as General Manager, Mr. Cowan served as the Agency's Assistant General Manager since December 2018. Prior to his appointment as Assistant General Manager, Mr. Cowan served as the Treasury Manager beginning in July 2012 and as the Assistant Treasury Manager beginning in October 2010. He began his employment with the Agency as a Senior Auditor in 2006, a position he held until his appointment as the Assistant Treasury Manager. Prior to his employment with the Agency, he was an Internal Auditor with Franklin Covey. Mr. Cowan holds a Bachelor of Science

degree in Business Administration from Southern Utah University and a Master of Business Administration degree from Brigham Young University.

Linford E. Jensen – Accounting Manager. Mr. Jensen first joined the Agency in 1993 as a Senior Auditor. He left the Agency in 1997 to work as the Manager of Financial Planning for Andalex Resources. Mr. Jensen returned to the Agency in 1998 as Audit Manager and was appointed Accounting Manager in October 2009. Prior to his first employment with the Agency, he was an auditor with Deloitte & Touche. Mr. Jensen holds a Bachelor of Arts degree in Accounting and a Master of Business Administration degree from the University of Utah and is a licensed Certified Public Accountant.

Vance K. Huntley – Treasury Manager. Mr. Huntley was appointed to the position of Treasury Manager in October 2020. Prior to his appointment as Treasury Manager, Mr. Huntley served as Audit Manager. Mr. Huntley began his employment with the Agency as Audit Manager starting in October 2009. Prior to his employment at the Agency, he was an Internal Audit Manager with The Church of Jesus Christ of Latter-day Saints, Chief Financial Officer with Xcel Fitness of Salt Lake City, Utah, Director of Finance with Infopia, Inc. of Salt Lake City, Utah and an Audit Manager with Deloitte & Touche LLP. Mr. Huntley holds a Bachelor of Science degree in Accounting and a Master of Accountancy/Information Systems degree from Brigham Young University and is a licensed Certified Public Accountant.

Cody R. Combe – Audit Manager. Mr. Combe was appointed to the position of Audit Manager in October 2020. He began his employment with the Agency as a Senior Auditor in June 2010, a position he held until his appointment as the Audit Manager. Prior to his employment with the Agency, he was an auditor with The Church of Jesus Christ of Latter-day Saints, and an auditor with Deloitte & Touche LLP. Mr. Combe holds a Bachelor of Arts degree in Accounting and a Master of Accountancy from the University of Utah and is a licensed Certified Public Accountant.

The Agency's staff, in addition to those listed above, consists of three other professionals and one secretarial/clerical employee serving in various administrative, financial and audit functions.

Investment Policy and Controls

The Resolution permits the Agency to invest its funds in Investment Securities. See "Investment of Certain Funds and Accounts" in APPENDIX A hereto and the definition of "*Investment Securities*" under "Definitions" in APPENDIX A hereto. The Resolution and the current investment policy of the Agency permit it to invest its funds in investments permitted under the Utah State Money Management Act, Utah Code Ann. § 51-7-1, *et seq*. The Agency does not currently have, nor does it expect to have in the future, any funds or monies which the Agency is or will be permitted to invest in investments other than Investment Securities as defined in the Resolution.

Pursuant to the Resolution, all investments in which the Agency invests amounts on deposit in the various Funds held by the Trustee under the Resolution are required to be reviewed by the Trustee for compliance with the Resolution. In addition, the Agency's internal auditors, at least annually, conduct extensive tests to determine whether the Agency's investments, including those investments made with amounts held by the Agency, are in compliance with the Resolution. The Agency has implemented various internal controls to assure that only proper authorized investments are made with the Agency's funds. The Agency does not presently have, nor does it intend to acquire in the future, derivative or leveraged investments or investments in mortgage-backed securities.

THE AGENCY'S FINANCING PROGRAM

General

On July 1, 1988, the Agency filed a certificate with the Trustee certifying completion of construction of the Initial Facilities. Based on (i) the Final Construction Cost Report, dated May 1994, prepared by the Project Manager, which was accepted by the Agency's Board of Directors and the Coordinating Committee and (ii) the payments-in-aid of construction made by SCPPA for cost of acquisition and construction of the Southern Transmission System as described below, the Agency determined that the funds provided from its Bonds and other debt securities had been sufficient to pay the construction costs for the Initial Facilities of the Project, interest during construction, reserve funds, working capital and financing expenses. All amounts held in the Initial Facilities Account in the Construction Fund that were not needed to pay the Cost of Acquisition and Construction of the Initial Facilities were released to the Agency for application to other Project purposes. Such amounts were used in prior years to reduce the costs of Project power.

The Agency may issue Bonds or Subordinated Indebtedness from time to time as it deems advisable to, among other things, (a) refund outstanding Bonds or Subordinated Indebtedness in order to reduce the Agency's annual debt service and thereby reduce the cost of Project power and energy and (b) finance the Cost of Acquisition and Construction of Capital Improvements to the Project.

SCPPA Financing of the Southern Transmission System

Pursuant to the Southern Transmission System Agreement (the "STS Agreement") between SCPPA and the Agency, SCPPA has undertaken to make payments-in-aid of construction to the Agency for all cost of acquisition and construction associated with the Southern Transmission System. The Agency has received from SCPPA all funds required for payment of all Costs of Acquisition and Construction of the initial facilities of the Southern Transmission System.

In consideration of SCPPA's agreement to make such payments-in-aid of construction, each of the California Purchasers has assigned to SCPPA its entitlement to capacity of the Southern Transmission System as set forth in such Power Purchaser's respective Power Sales Contract. Each California Purchaser has also entered into a Transmission Service Contract with SCPPA pursuant to which such Power Purchaser is entitled to transmission service, utilizing the capacity of the Southern Transmission System assigned to SCPPA by the California Purchasers, to the extent of such Power Purchaser's Southern Transmission Entitlement Share (see "POWER PURCHASERS' COST AND ENTITLEMENT SHARES" in APPENDIX B hereto) and is obligated to make monthly payments therefor on a "take-or-pay" basis. Such monthly payment obligations include, in addition to amounts in respect of SCPPA's operating costs for providing transmission service and debt service on the bonds issued by SCPPA to finance and refinance the payments-in-aid of construction made by it to the Agency for the Southern Transmission System, Monthly Power Costs allocable to the Southern Transmission System. SCPPA is obligated to pay to the Agency out of such monthly payments the California Purchasers' Monthly Power Costs under their respective Power Sales Contracts allocable to the Southern Transmission System. Such payments received by the Agency will be applied to discharge the California Purchasers' obligation to pay Monthly Power Costs under their respective Power Sales Contracts. The California Purchasers will, however, remain liable to pay such Monthly Power Costs to the extent not so discharged.

On October 20, 2008, the Agency's Board of Directors and the Coordinating Committee approved an upgrade to the Southern Transmission System (the "STS Upgrade") that was completed in December 2010. The STS Upgrade increased the capacity of the Southern Transmission System to a total capacity of 2,400 MW. The STS Upgrade was financed through payments-in-aid of construction made by SCPPA in a manner similar to the financing of the construction costs of the initial facilities of the Southern

Transmission System ("STS Upgrade Payments"), as provided in a First Amendment to Southern Transmission System Agreement, dated as of November 1, 2008.

By separate action, on October 20, 2008, the Agency's Board of Directors also created a Fund under the Resolution known as the STS Upgrade Construction Fund, which was a fund held by the Agency to hold STS Upgrade Payments and disburse them to pay construction costs for the STS Upgrade. The STS Upgrade Construction Fund was separate and distinct from the other Funds created by the Resolution (see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Flow of Funds"), and no portion of any payments made by the Power Purchasers pursuant to their Power Sales Contracts was to be deposited therein. The STS Upgrade Construction Fund constituted a part of the Trust Estate under the Resolution. The Agency understands that the STS Upgrade is now complete and does not anticipate any additional STS Upgrade Payments to be made to the STS Upgrade Construction Fund. As a result, the STS Upgrade Construction Fund has been closed.

On August 4, 2020, the Coordinating Committee and the Agency's Board of Directors authorized the Project Manager to commence discussions with SCPPA relative to the financing of the STS Renewal Project. The Agency and SCPPA have negotiated an amendment to the STS Agreement to address such capital improvements and a renewal STS agreement to address the payments-in-aid of construction related to further capital improvements to the Southern Transmission System following the termination of the STS Agreement. Substantial completion of the STS Renewal Project is anticipated to occur after the commercial operation date of the Generation Renewal Project. Even so, it is expected that SCPPA will issue its bonds or other obligations in amounts and at times sufficient to make to the Agency all payments-in-aid of construction related to the STS Renewal Project as are necessary to permit the elements of the STS Renewal Project that are necessary to the operation of the Project after giving effect to the Generation Renewal Project to be completed on or before the date on which the Generation Renewal Project achieves commercial operation.

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FISCAL YEAR 2021-2022 ANNUAL BUDGET

The Operating Agent has prepared, and the Coordinating Committee has approved, an operating budget for fiscal year 2021-2022, which began on July 1, 2021. A summary of the fiscal year 2021-2022 Annual Budget adopted by the Agency's Board of Directors (which incorporates such operating budget, as amended, and as such Annual Budget has been amended) is set forth below:

INTERMOUNTAIN POWER AGENCY
FISCAL YEAR 2021-2022 ANNUAL BUDGET SUMMARY
($000)

	Generation Station	Northern Transmission System	Southern Transmission System	Total[1]	H2 Betterment Per CC-2020-011[2]	IGS Decom-missioning Pre-Funding[2]
Minimum Cost Component:						
Net Debt Service[3, 4]	52,984	1,344	(22)	54,306		
Operations	31,679	2,537	14,661	48,876		
Maintenance	51,359	1,246	12,835	65,440		
Renewals and Replacements	14,159	778	5,120	20,057	7,000	54,000
Indirect Labor[5]	18,437	0	1,254	19,690		
Taxes	10,236	319	3,084	13,639		
Risk Management	5,942	74	1,373	7,390		
Administrative and General[6]	10,085	78	3,258	13,422		
Fixed Fuel	113,172	0	0	113,172		
Total Minimum Costs[1]	308,054	6,375	41,563	355,992		
Variable Cost Component	96,155	0	0	96,155		
Total Operating Budget[1]	404,209	6,375	41,563	452,147	7,000	54,000
Total Agency Annual Budget[1]	404,209	6,375	41,563	452,147	7,000	54,000

1 Row and column totals may not add due to rounding.
2 Amount billed separately to the Department, Burbank and Glendale for hydrogen-related betterments as part of the Generation Renewal Project. Approved by Coordinating Committee Resolution No. CC-2020-011 (with respect to the Operating Budget) and Agency Board of Directors Resolution No. IPA-2020-014 (with respect to the Agency's Annual Budget). Not reflected in the "Total" column.
3 Total debt service on all Agency obligations, plus ongoing financing expenses, less estimated interest earnings available to reduce power costs.
4 Excludes SCPPA debt service costs which are not part of the Agency's Annual Budget.
5 Labor costs for IPSC.
6 Excludes certain SCPPA costs which are not part of the Agency's Annual Budget.

For a description of the circumstances under which the Agency is required to adopt an amended Annual Budget, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS – Budgeting" above.

COORDINATING COMMITTEE

Pursuant to the Power Sales Contracts, the Coordinating Committee, among other functions, provides liaison among the Agency and the Power 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 the Agency regarding the financing of the Project. The 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 the Agency.

The Coordinating Committee consists of the Chairman, who is a non-voting representative appointed by the Agency, and representatives of the Power Purchasers or groups thereof. The Chairman of the 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 Power Purchasers having voting rights (which equal the respective Power Purchasers' Generation Entitlement Shares) aggregating at least 80%.

The Coordinating Committee presently consists of its Chairman (the General Manager of the Agency), and the following voting representatives:

Power Purchaser(s) Represented	Representative	Voting Rights Percentage
Murray City	Blaine J. Haacke	4.000%
City of Logan	Mark Montgomery	2.469
All Other Utah Municipal Purchasers	Eric Larsen	7.571
Moon Lake Electric Association, Inc.	Yankton Johnson	2.000
Mt. Wheeler Power, Inc.	Kevin Robison	1.786
All Other Cooperative Purchasers	LaDel Laub	3.231
Department of Water and Power of The City of Los Angeles	Paul R. Schultz	48.617
City of Anaheim	Dukku Lee	13.225
City of Burbank	Dawn Roth Lindell	3.371
City of Glendale	Chie Valdez	1.704
City of Pasadena	Shari Thomas (alt.)	4.409
City of Riverside	Todd M. Corbin	7.617
		100.000%

For additional discussion of the responsibilities and functions of the Coordinating Committee, see "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS – Coordinating Committee" and "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT – Coordinating Committee" in APPENDIX B hereto.

RENEWAL CONTRACT COORDINATING COMMITTEE

Pursuant to the Renewal Power Sales Contracts, from and after the Transition Date, the Renewal Contract Coordinating Committee, among other functions, provides liaison among the Agency and the Renewal Power 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 the Agency regarding the financing of the Project. From and after the Transition Date, the Renewal Contract 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 (other than Essential Capital Improvements,

as defined in the Renewal Power Sales Contracts) proposed to be undertaken by the Agency. Prior to the Transition Date, the Renewal Contract Coordinating Committee's authority is limited to considering matters related to Transition Project Indebtedness and other matters requiring Renewal Contract Coordinating Committee approval prior to the Transition Date pursuant to the Power Sales Contracts or the Renewal Power Sales Contracts and to receive financial statements and operating reports provided to the Coordinating Committee in the ordinary course of business. The Renewal Contract Coordinating Committee's approval is required for the issuance of Transition Project Indebtedness for purposes other than financing the Gas Repowering (so long as the Transition Project Indebtedness satisfies the requirements related to Substantially Equal Debt Service (as defined in the Renewal Power Sales Contracts).

The Renewal Contract Coordinating Committee consists of the Chairman, who is a non-voting representative appointed by the Agency, and representatives of the Renewal Power Purchasers or groups thereof. The Chairman of the Renewal Contract Coordinating Committee may, at their own discretion, and must, at the request of any member of the Renewal Contract Coordinating Committee, call a meeting of the Renewal Contract Coordinating Committee. All actions taken by the Renewal Contract Coordinating Committee require the affirmative vote of representatives of Power Purchasers having voting rights (which equal the respective Power Purchasers' Generation Entitlement Shares) aggregating at least 80% (except that modifications affecting the minimum cost component of Project Fuel, as permitted under the Renewal Power Sales Contracts, require 100% of such voting rights).

The Renewal Contract Coordinating Committee presently consists of the General Manager of the Agency, as Chairman, and the following voting representatives:

Power Purchaser(s) Represented	Representative	Voting Rights Percentage
Murray City	Blaine J. Haacke	4.036%
City of Logan	Mark Montgomery	2.491
City of Bountiful	Allen Johnson	1.711
All Other Utah Municipal Purchasers	Eric Larsen	5.737
Moon Lake Electric Association, Inc.	Yankton Johnson	2.018
Mt. Wheeler Power, Inc.	Kevin Robison	1.803
All Other Cooperative Purchasers	LaDel Laub	3.261
Department of Water and Power of The City of Los Angeles	Paul R. Schultz	71.442
City of Burbank	Dawn Roth Lindell	3.334
City of Glendale	Chie Valdez	4.167
		100.000%

For additional discussion of the responsibilities and functions of the Renewal Contract Coordinating Committee, see "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS – Renewal Contract Coordinating Committee" and "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT – Renewal Contract Coordinating Committee" in APPENDIX B hereto.

PROJECT OPERATIONS

General

The Project's coal-fired steam-electric generating plant and associated facilities were constructed to provide the Power Purchasers with reliable electrical energy while reducing their dependence on oil- and

natural gas-fired generation. This section briefly describes the construction, management and operation of the Project, its delivery of energy, and certain matters affecting Project operations (such as fuel and water supplies, government licenses and permits, and insurance).

Management and Operation of the Project

Management and Work Force. Project operations are managed for the Agency by the Department under the terms of the Construction Management and Operating Agreement. The Department's operating activities are subject to the oversight of the Coordinating Committee. See "COORDINATING COMMITTEE" above. In operating the Intermountain Generating Station, the Intermountain Converter Station and the Railcar Service Center, the Operating Agent uses personnel from IPSC. The International Brotherhood of Electrical Workers (the "IBEW") has been certified as the collective bargaining representative of IPSC employees. The collective bargaining agreement between these parties was renewed on July 1, 2018 and expires on June 30, 2022. Remaining Project facilities are managed by the Operating Agent's own personnel.

Operating Experience. Generally, Project facilities have operated with a high degree of availability, exceeding the average of coal-fired generating units of comparable size. Neither the Agency 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.

The Agency has seen, however, a decline in the utilization of the Project since 2016 as a result of the California GHG Initiatives. Such GHG initiatives are expected to put downward pressure on the utilization rate of the Project for the foreseeable future. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – California Greenhouse Gas Initiatives – *Impacts on the Agency*" above.

Removal of Coal Units from Service. On May 22, 2017, the Agency's Board of Directors determined that the coal-fired units at the Project will be removed from service by the commercial operation date of the gas-fired power blocks to be constructed as part of the Gas Repowering (which is scheduled for 2025). The Coordinating Committee approved the removal as well. In response to requirements of the CCR Rules, the Agency has determined to cease operation of the coal-fired boilers by the deadline of 2028 imposed in the CCR Rules. The Agency anticipates that based on its intended course of action to remove the coal-fired units from service by 2025, it will have satisfied the requirement of the CCR Rules to cease operation of the coal-fired boilers in advance of the deadline under the CCR Rules.

Operating Statistics. The operating results of the Project during fiscal years 2017-2018 through 2020-2021 are shown in the following table. Based on the historical experience of comparable generating units, the Project would be expected to continue to achieve on a long-term basis the above-average levels of performance demonstrated to date with respect to the following metrics set forth in the table below: Operating Availability, Equivalent Availability and Net Unit Heat Rate (BTU/kWh). The Project is not expected to achieve above-average levels of performance with respect to the metric of Plant Capacity Factor shown in the table below. The Agency anticipates that the Project's capacity factor (and, consequently, Gross Energy Generated (MWh) and Net Energy Generated (MWh)) will depend on system demand, market conditions and the application of the GHG Cost Factor, and may be impacted by other factors discussed elsewhere in this Official Statement. See "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – California Greenhouse Gas Initiatives – *Impacts on the Agency*" above.

	Fiscal Year 2017-18[1]	Fiscal Year 2018-19[2]	Fiscal Year 2019-20[3]	Fiscal Year 2020-21[4]	Industry Average Calendar Years 2016-2020[5]
Gross Energy Generated (MWh)					
Unit 1	4,261,679	4,659,056	3,724,186	3,808,747	4,248,162
Unit 2	4,481,691	4,687,699	3,642,927	4,070,442	4,248,162
Net Energy Generated (MWh)					
Unit 1	3,969,248	4,335,642	3,443,031	3,537,724	4,012,311
Unit 2	4,155,748	4,368,207	3,362,157	3,763,675	4,012,311
Plant Capacity Factor[6]					
Unit 1	50.35%	54.99%	43.55%	44.87%	54.73%
Unit 2	52.71%	55.41%	42.53%	47.74%	54.73%
Operating Availability[7]					
Unit 1	89.80%	94.19%	96.53%	85.20%	81.32%
Unit 2	97.02%	90.08%	93.27%	94.91%	81.32%
Equivalent Availability[8]					
Unit 1	88.87%	94.07%	96.48%	85.17%	79.12%
Unit 2	96.64%	90.00%	93.21%	94.36%	79.12%
Net Unit Heat Rate (BTU/kWh)[9]					
Unit 1	9,981	9,927	10,428	10,174	10,976
Unit 2	10,022	9,812	10,324	10,247	10,976

(1) Reflects outages during the 2017-2018 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 2 spring 2018 (1 week) and Unit 1 spring 2018 (5 weeks)), unplanned maintenance outages (Unit 1 (22.95 hours) and Unit 2 (49.90 hours) and forced outages (Unit 1 (4.37 hours) and Unit 2 (0 hours)).

(2) Reflects outages during the 2018-2019 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 2 spring 2019 (5.1 weeks) and Unit 1 spring 2019 (8.8 days)), unplanned maintenance outages (Unit 1 (3.7 days) and Unit 2 (0 days) and forced outages (Unit 1 (8.7 days) and Unit 2 (0 days)).

(3) Reflects outages during the 2019-2020 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 2 spring 2020 (3.49 weeks) and Unit 1 spring 2020 (8.86 days)), unplanned maintenance outages (Unit 1 (0 days) and Unit 2 (0 days) and forced outages (Unit 1 (3.86 days) and Unit 2 (0.22 days)).

(4) Reflects outages during the 2020-2021 fiscal year consisting of the following (expressed as aggregate periods per unit): scheduled maintenance outages (Unit 1 spring 2021 (7.24 weeks) and Unit 2 spring 2021 (9.30 days)), unplanned maintenance outages (Unit 1 (3.24 days) and Unit 2 (5.90 days) and forced outages (Unit 1 (0.07 days) and Unit 2 (3.37 days)).

(5) 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 42 units in the years 2016 through 2020 (5-year average), which is the most recent information currently available, 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 ("EIA") for 2020 for the top 25 largest western coal-fired power plants. Such NERC and EIA reports are calendar-year based.

(6) 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.

(7) 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.

(8) The Equivalent Availability Factor provides an adjustment of the Operating Availability by incorporating the effect of de-ratings (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.

(9) 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.

Project Energy Delivery

The output of the Project is delivered to the Power Purchasers at points of delivery designated by them from among the Switchyard, the Mona and Gonder Switchyards of the Northern Transmission System, and the Adelanto Converter Station of the Southern Transmission System. Each of the Power 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 California Purchasers have each designated the Adelanto Converter Station as their point of delivery. 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. Transmission services for California Purchasers Glendale and Burbank to their electric systems are provided by the Department. Transmission services for California Purchaser Pasadena to its electric system are currently provided by the Department and the CAISO. The CAISO handles deliveries for Anaheim and Riverside. The Adelanto Converter Station also is connected to the Mead-Adelanto Transmission Project.

PacifiCorp provides transmission services for the Utah 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).

The Utah Municipal Power Purchasers are members of UAMPS, which has entered into a long-term transmission agreement with PacifiCorp under which PacifiCorp provides certain transmission services for the members of UAMPS, including transmission of the Utah Municipal Power Purchasers' entitlement to Project power from the Mona Switchyard to the Utah Municipal Power Purchasers' respective points of delivery for their distribution systems.

Interconnections to the Project

In the spring of 2008, the Agency and Milford Wind I entered into a Generator Interconnection Agreement (the "GIA"). Pursuant to the GIA, the Agency granted to Milford Wind I the right, subject to the terms, conditions and limitations of the GIA, to interconnect the Milford Wind I Project to the transmission systems of the Project through the Switchyard. The GIA, however, grants Milford Wind I no right or entitlement to use any of the capacity of the Switchyard, the Southern Transmission System or the Northern Transmission System. Rather, Milford Wind I is permitted to connect to Project transmission facilities for the purpose of delivering capacity and energy from the Milford Wind I Project through the Switchyard only if and to the extent adequate transmission capacity is made available to Milford Wind I by Power Purchasers, subject to the maximum amount of megawatts identified in certain applicable stability and steady state studies.

Pursuant to an assignment of a portion of Milford Wind I's entitlement to Milford Wind II, in 2010, the Agency and Milford Wind II negotiated and executed a GIA. The second GIA provides for interconnection capacity for the Milford Wind II Project, in addition to the Milford Wind I Project, to the transmission systems of the Project through the Switchyard.

Certain of the California Purchasers have arranged to take delivery of all power delivered by the Milford Wind Projects at a point immediately before the point at which Milford Wind I's and Milford Wind II's transmission lines cross the boundary of the Switchyard. The California Purchasers are using and anticipate using entitlements in the Southern Transmission System that they currently hold and that they may acquire to connect such power to the Southern Transmission System through the Switchyard, and transmit it to their point of delivery at Adelanto, California. With the completion of the STS Upgrade, the California Purchasers have sufficient capacity to transmit this power. Pursuant to the Power Sales Contracts, power generated by the Intermountain Generating Station takes priority, however, over any power generated by any other sources for purposes of scheduling the capacity and use of the Switchyard and transmission systems of the Project.

In 2010, the Agency also granted interconnection rights to the Department at the Adelanto Converter Station for delivery of up to 10 MW of power generated by the Department's solar project near Adelanto, California.

The Agency has thirteen active interconnection requests. The requests are for 6,804 MW total and represent renewable energy sources including wind and solar energy. The Agency's review of the applications is on hold pending completion of system impact, facilities and harmonics studies. See "ELECTRIC INDUSTRY RESTRUCTURING – Federal Deregulation Actions – *FERC Open-Access Transmission Initiatives*" above.

Fuel Supply

During fiscal year 2020-2021, Unit 1 operated at a plant capacity factor of 44.87% and Unit 2 operated at a plant capacity factor of 47.74%. Coal consumption during that fiscal year was approximately 3.3 million tons.

At this time, deliveries for contracted coal are constrained by the global logistics crisis and the national labor shortage. The Operating Agent anticipates these constraints will remain for calendar year 2022 with anticipated improvement in calendar year 2023. Accordingly, Project participants have determined to dispatch the Project at minimum capacity, which includes running only one of the two generating units, during the first two quarters of 2022 to increase the likelihood of a sufficient coal supply during the third quarter of 2022.

The Agency expects the costs to fulfill the Project's annual coal supply requirements after 2022 will be higher than its current contract costs due to global logistics crisis and fuel supply shortages, 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, though the Agency's coal prices for 2022 are set by contracts (including price escalation provisions in those contracts).

The Operating Agent manages a diversified portfolio of coal supply agreements that provide for the coal requirements for the Intermountain Generating Station. The Operating Agent has determined that coal presently under contract is sufficient, with the exercise of available options, to meet the Intermountain Generating Station's annual coal requirements through 2023, with lesser amounts of coal under contract through 2024. The cost of coal delivered to the Intermountain Generating Station is on par with market prices for the region.

To be able to continue to operate the Project in the event of a disruption in the Project's coal supply, the Agency attempts to maintain a coal stockpile at the Intermountain Generating Station that is sufficient to operate the Intermountain Generating Station at anticipated plant capacity factors for a minimum of 60 days. As of April 1, 2022, at the current budgeted capacity factor, the Agency has approximately 92 days of inventory of coal. The Agency does not expect the Project to operate, on average, in excess of the budgeted capacity factor over the course of the current fiscal year.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between the Agency and the Union Pacific Railroad company, and the coal is transported, in part, in Agency-owned railcars. Coal is also transported, to some extent, in commercial trucks.

Through the execution of the Natural Gas Transportation Contract, the Agency has secured firm natural gas transportation capacity sufficient to deliver 100% of the natural gas required to operate the Generation Renewal Project at projected capacity factors through 2045. The Agency is studying the manner of acquiring natural gas supply best suited for the Project, though the Agency anticipates that such natural gas will be obtained at the hub at Opal, Wyoming, consistent with the terms of the Natural Gas Transportation Contract.

Water Supply

The Agency owns water rights and water shares (primarily from the Sevier River) that, combined, 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. Should there be an interruption in the water supply system customarily used for operation 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 the Intermountain Generating Station and the Intermountain Converter Station for about twenty-five (25) days at full plant loads.

The Project currently uses approximately 12,500 acre-feet annually. After giving effect to the Generation Renewal Project, water usage is projected to be reduced to approximately 6,500 acre-feet per year.

The Agency anticipates making water available for development of the salt caverns for storage of hydrogen fuel in the amount of approximately 7,000 acre-feet per year for two years. The Agency projects that water usage for hydrogen fuel production could increase by a maximum of approximately 2,400 acre-feet annually (assuming that all energy at the Project is generated using 100% hydrogen fuel).

The Agency's water rights (and the water rights underlying its water shares) were permitted by the State of Utah assuming that 100% of the water used in the Project would constitute depletion (i.e., no water used by the Project would return to the water system from which the water is drawn pursuant to the Agency's water rights and water shares). A significant portion of the water used by the Project each year is, in fact, returned to the water system from which it has been taken.

Permits, Licenses and Approvals

To the Agency's knowledge, the Project has been designed, constructed and operated in compliance with all applicable federal, state and local regulations, codes, standards and laws. To the Agency's knowledge, all principal permits, licenses, grants and approvals required to construct and operate the current facilities of the Project have been acquired, including permits relating to air quality and rights-of-way on federally-owned land.

The Agency is in the process of obtaining the permits necessary for design, construction and operation of the Gas Repowering, the Hydrogen Betterments and the STS Renewal Project. The air permit from the Utah Department of Air Quality is the remaining outstanding permit of which the Agency is aware at this time. Permitting under the Natural Gas Transportation Contract and with respect to the Hydrogen Production and Storage Capacity are the responsibilities of the respective third parties with which the Agency has contracted for its natural gas transportation and hydrogen production and storage capacity.

Insurance

Pursuant to the Resolution, the Agency is required to use its best efforts to insure or cause to be insured the properties of the Project which are of an insurable nature and of the character usually insured by those operating properties similar to the Project against loss or damage by fire and from other causes customarily insured against and in such relative amounts and having such deductibles as are usually obtained. The Resolution also requires the Agency to use its best efforts to maintain or cause to be maintained insurance or reserves against loss or damage from hazards and risks to the person and property of others as are usually insured or reserved against by those operating properties similar to the properties of the Project. The Operating Agent acts as the Agency's agent in obtaining and maintaining insurance for the Project.

The Agency's insurance program for the Project consists of a combination of commercial insurance policies, fidelity bonds and self-insurance. In the opinion of the Operating Agent, the coverages and limits provided by the Agency's insurance program conform to those customarily provided by utilities in the public power industry. In connection with its self-insurance program, the Agency has established the Self-Insurance Fund under the Resolution. See "Application of Revenues" and "Insurance" in APPENDIX A hereto.

LITIGATION

General

At the time of delivery of the 2022 Series A and B Bonds, the Agency will certify that there is no litigation or other proceeding pending or, to the knowledge of the Agency, threatened in any court, agency or other administrative body (either state or federal) restraining or enjoining the authorization, issuance, sale or delivery of the 2022 Series A and B Bonds or the collection of Revenues, or in any way questioning or affecting: (i) the proceedings under which the 2022 Series A and B Bonds are to be issued, (ii) the validity of any provision of the 2022 Series A and B Bonds or the Resolution, (iii) the pledges by the Agency under the Resolution, (iv) the validity or enforceability of the Power Sales Contracts, the Renewal Power Sales Contracts, the Excess Power Sales Agreement or the Agreement for Sale of Renewal Excess Power or (v) the legal existence of the Agency or the title to office of the officials of the Agency.

Appeals of Fees in Lieu of Property Taxes

In the State, each year the Property Tax Division of the Utah State Tax Commission (the "Division") determines the value of the Agency's tangible property located within the State (the "Taxable Tangible Property") and then various counties in Utah (the "Counties") assess fees in lieu of property tax (the "Fees") to the Agency based on such valuation. The Division's annual valuations are subject, during a specified period, to the right of the Agency or the Counties to appeal such valuations to the Utah State Tax Commission (the "Commission"). When a valuation is appealed to the Commission, the appeal is tried before the Commission as the adjudicative body. In such an appeal, the Commission has the obligation to determine the fair market value of the Taxable Tangible Property. The Division has the right to appear as a party before the Commission in such an appeal to defend the Division's valuation as being equal to fair market value.

The Agency has appealed the Division's valuation of the Taxable Tangible Property for each of the years 2014 through 2021 (relevant Fees will be determined by a statutory formula that is to be calculated solely on the basis of the valuation that will be determined by a final nonappealable decision of the Commission or the court). The Agency has paid the assessed Fees for each year on appeal and is seeking to obtain a refund of the Fees attributable to the amount by which the Division's valuation of the Taxable Tangible Property exceeds the fair market value of the Taxable Tangible Property. The appeal of the 2014 Valuation (as defined below) has been heard by the Commission.

The Fees assessed by the Counties to the Agency in 2014 (the "2014 Fees") were based on the valuation by the Division of the Taxable Tangible Property at $829,450,170 (the "2014 Valuation"). After the Counties assessed the 2014 Fees, the Division asserted that the 2014 Valuation reflected a computational error and that the Taxable Tangible Property had a value in 2014 of $1,031,520,000. In connection with the Agency's appeal of the 2014 Valuation, the seven Counties that are the beneficiaries of the 2014 Fees asserted a valuation that was approximately the same as the valuation that the Division asserted after the assessment of the 2014 Fees. The Agency asserted that, for 2014, the Taxable Tangible Property had a fair market value of $499,000,000.

The 2014 Fees have reflected the Division's exclusion from the Fee base of a percentage of the Fee base equal to the percentage of power purchased from the Agency by the Utah Municipal Purchasers (the "Municipal Exclusion"). The State has conceded in assessing the 2014 Fees (and in earlier years) that since the Agency sells at least a portion of the Project's generation capacity and output to Utah municipalities pursuant to the Power Sales Contracts between the Agency and such municipalities, a proportionate portion of the value of the Agency's Taxable Tangible Property should be excluded from the Fee base in calculating the Fees. The 2014 Valuation and the valuation advocated by the Agency in the appeal of the 2014 Valuation and the 2014 Fees reflected a Municipal Exclusion of 14.04%. The valuation proposed by the Division following such assessment reflected a Municipal Exemption of 11.193% (reflecting a change in the Division's position following the assessment of the 2014 Fees).

After the trial of the 2014 Valuation (held in 2016), the Division, Millard County and the Agency filed their respective briefs setting forth their positions with respect to the Municipal Exclusion. In those briefs, the Agency, the Division and Millard County asserted that the Municipal Exclusion should be equal to 14.04%, 11.193% and 0%, respectively.

On December 22, 2017, the Commission issued its decision with respect to the 2014 Valuation. The Commission ordered that the value of the Taxable Tangible Property be $751,495,000 (after giving effect to a Municipal Exclusion of 14.04%). The Counties appealed the Commission's decision to a State district court (sitting as a tax court, the "Tax Court"). The Agency then cross-appealed the Commission's order. Because the Division is a division within the Commission, the Division has no right to appeal the Commission's decision with respect to the 2014 Valuation (including the amount of the Municipal Exclusion). The Commission does have the right to appear in the Tax Court proceedings to argue that the Tax Court should uphold the Commission's order.

The appeal to the Tax Court will result in a trial de novo (with no deference to the findings of fact or conclusions of law made by the Commission). The appeal to the Tax Court has stayed any refunds required to be made by the Counties pursuant to the Commission's order pending a final non-appealable order. The Tax Court has ordered that the Agency and the Counties proceed with discovery in the appeal. The Tax Court will set the date for trial of the appeal once discovery is complete. Completion of discovery has been pending ongoing discussions relating to a potential deposition of a third party. The timing for discovery has been subject to continued extensions over the past several months.

The Agency, the Commission, and the Counties have filed a stipulation with the Tax Court providing that the proceedings in the appeals are to be protected from public disclosure.

Any of the Counties or the Agency may appeal a decision by the Tax Court directly to the Utah Supreme Court. Although the parties would have the right to have such appeal heard, the Utah Supreme Court has the discretion to hear the appeal itself or to have the appeal heard by the Utah Court of Appeals. If the Utah Supreme Court elects to have the Utah Court of Appeals hear the appeal, the Utah Supreme Court would then have the discretion to decline to hear any appeal of the Utah Court of Appeals' decision.

The Commission has ordered that the appeals regarding Valuations for 2015 through 2021 would be informally stayed to allow the appeal of the 2014 Valuation to be tried in court.

The Agency cannot predict the outcome of any appeal of the Commission's order including with respect to the assessed value of the Agency's property. The Tax Court will not be limited to the original determination by the Commission of fair value made in connection with the assessment of the 2014 Fees. The Tax Court, with respect to the 2014 appeals, or the Commission, with respect to the appeals for the remaining years, may determine that the fair value of the Taxable Tangible Property exceeds the valuation for the year or years before it or that the Municipal Exclusion is as low as 0% (concluding that the Agency would owe more fees), including even if the Agency withdrew its appeal.

The Agency cannot predict the effect of the Commission's decision with respect to the 2014 Valuation or the 2014 Fees including the impact of the decision following the exhaustion of any appeals (during the pendency of which the Commission's order is stayed) will have on the Commission's determinations with respect to the valuation or the Fees with respect to later years on appeal. The Agency cannot estimate the amount or range of potential loss or impact on the Agency's financial condition, if any, from enforcement of the Commission's decision with respect to the 2014 Valuation and the 2014 Fees, an adverse determination by a reviewing court with respect to the 2014 Valuation or the 2014 Fees or the determination by the Commission or a reviewing court with respect to the valuation or the Fees for subsequent years.

RATINGS

Moody's has assigned a rating of "Aa3" and a stable ratings outlook to the 2022 Series A and B Bonds and Fitch has assigned a rating of "AA-" and a stable ratings outlook to the 2022 Series A and B Bonds.

The respective ratings and outlooks by Moody's and Fitch of the 2022 Series A and B Bonds reflect only the views of such organizations and any desired explanation of the significance of such ratings and outlooks or any other statements given by the rating agencies with respect thereto should be obtained from the rating agency furnishing the same, at the following addresses: Moody's Investors Service, 7 World Trade Center at 250 Greenwich Street, New York, New York 10007; and Fitch Ratings, One State Street Plaza, New York, New York 10004. Generally, a rating agency bases its rating and outlook (if any) on the information and materials furnished to it and on investigations, studies and assumptions of its own. There is no assurance that such ratings or outlooks will be in effect for any given period of time or that they will not be revised upward or downward or withdrawn entirely by such rating agencies if, in the judgment of such agencies, circumstances so warrant. Any such downward revision or withdrawal of any ratings may have an adverse effect on the market price of the 2022 Series A and B Bonds.

TAX MATTERS

2022 Series A Bonds

In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency ("Bond Counsel"), based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code"). Bond Counsel is of the further opinion that interest on the 2022 Series A Bonds is not a specific preference item for purposes of the federal alternative minimum tax. Bond Counsel is also of the opinion that interest on the 2022 Series A Bonds is exempt from individual income taxes imposed by the State of Utah. Bond Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2022 Series A Bonds. A complete copy of the proposed form of opinion of Bond Counsel is set forth as APPENDIX I hereto.

To the extent the issue price of any maturity of the 2022 Series A Bonds is less than the amount to be paid at maturity of such Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the 2022 Series A Bonds which is excluded from gross income for federal income tax purposes and is exempt from individual income taxes imposed by the State of Utah. For this purpose, the issue price of a particular maturity of the 2022 Series A Bonds is the first price at which a substantial amount of such maturity of the 2022 Series A Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in

the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the 2022 Series A Bonds accrues daily over the term to maturity of such Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such 2022 Series A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Bonds. Beneficial Owners of the 2022 Series A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of 2022 Series A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Bonds in the original offering to the public at the first price at which a substantial amount of such Bonds is sold to the public.

2022 Series A Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the 2022 Series A Bonds. The Agency has made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the 2022 Series A Bonds will not be included in federal gross income (see "DESCRIPTION OF THE 2022 SERIES A AND B BONDS – Tax Covenants" herein). Inaccuracy of these representations or failure to comply with these covenants may result in interest on the 2022 Series A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the 2022 Series A Bonds. The opinion of Bond Counsel assumes the accuracy of these representations and compliance with these covenants. Bond Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken), or events occurring (or not occurring), or any other matters coming to Bond Counsel's attention after the date of issuance of the 2022 Series A Bonds may adversely affect the value of, or the tax status of interest on, the 2022 Series A Bonds. Accordingly, the opinion of Bond Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Bond Counsel is of the opinion that interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of amounts treated as interest on, the 2022 Series A Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Bond Counsel expresses no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the Code or court decisions may cause interest on the 2022 Series A Bonds to be subject, directly or indirectly, in whole or in part, to federal income taxation or to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such legislative proposals or clarification of the Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the 2022 Series A Bonds. Prospective purchasers of the 2022 Series A Bonds should consult their own tax advisors regarding the potential impact of any pending or proposed federal or state tax legislation, regulations or litigation, as to which Bond Counsel expresses no opinion.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the 2022 Series A Bonds for federal income tax purposes. It is not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, Bond Counsel cannot give and has not given any opinion or assurance about the future activities of the Agency, or about the effect of future changes in the Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. The Agency has covenanted, however, to comply with the requirements of the Code.

Bond Counsel's engagement with respect to the 2022 Series A Bonds ends with the issuance of the 2022 Series A Bonds, and, unless separately engaged, Bond Counsel is not obligated to defend the Agency or the Beneficial Owners regarding the tax-exempt status of the 2022 Series A Bonds in the event of an audit examination by the IRS. Under current procedures, Beneficial Owners would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which the Agency legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the 2022 Series A Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the 2022 Series A Bonds, and may cause the Agency or the Beneficial Owners to incur significant expense.

Payments on the 2022 Series A Bonds generally will be subject to U.S. information reporting and possibly to "backup withholding." Under Section 3406 of the Code and applicable U.S. Treasury Regulations issued thereunder, a non-corporate Beneficial Owner of 2022 Series A Bonds may be subject to backup withholding with respect to "reportable payments," which include interest paid on the 2022 Series A Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the 2022 Series A Bonds. The payor will be required to deduct and withhold the prescribed amounts if (i) the payee fails to furnish a U.S. taxpayer identification number ("TIN") to the payor in the manner required, (ii) the IRS notifies the payor that the TIN furnished by the payee is incorrect, (iii) there has been a "notified payee underreporting" described in Section 3406(c) of the Code or (iv) the payee fails to certify under penalty of perjury that the payee is not subject to withholding under Section 3406(a)(1)(C) of the Code. Amounts withheld under the backup withholding rules may be refunded or credited against a Beneficial Owner's federal income tax liability, if any, *provided, however*, that the required information is timely furnished to the IRS. Certain Beneficial Owners (including among others, corporations and certain tax-exempt organizations) are not subject to backup withholding. The failure to comply with the backup withholding rules may result in the imposition of penalties by the IRS.

2022 Series B Bonds

Interest on 2022 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. Bond Counsel is of the opinion that interest on the 2022 Series B Bonds is exempt from individual income taxes imposed by the State of Utah. Bond Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2022 Series B Bonds. A complete copy of the proposed form of opinion of Bond Counsel is set forth as APPENDIX I hereto.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2022 Series A and B Bonds from the Agency at a purchase price equal to the aggregate of the initial public offering prices of the 2022 Series A and B Bonds as reflected in the prices or yields set forth on the inside front cover of this Official Statement, and to make a public offering of the 2022 Series A Bonds at not higher than the prices or lower than the yields set forth on the inside front cover of this Official Statement,

plus accrued interest, if any. The Agency has agreed to pay to the Underwriters an amount equal to approximately 0.214% of the principal amount of the 2022 Series A and B Bonds as the Underwriters' discount. The Underwriters will be obligated to purchase all the 2022 Series A and B Bonds if any such 2022 Series A or B Bonds are purchased. The Underwriters are BofA Securities, Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC.

The 2022 Series A and B Bonds may be offered and sold to certain dealers (including underwriters and other dealers depositing such Bonds into investment trusts) at prices lower than the public offering prices or at yields greater than the public offering yields set forth on the inside front cover of this Official Statement, and such public offering prices or yields may be changed, from time to time, by the Underwriters.

Certain of the Underwriters have entered into distribution agreements or other written agreements with other broker-dealers for the distribution of the 2022 Series A and B Bonds at the initial public offering prices. Such agreements generally provide that the relevant Underwriter will share a portion of its underwriting compensation or selling concession with such broker-dealers.

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. In addition, any of the Underwriters or their affiliates may extend credit to the Agency pursuant to a credit or loan agreement. The Underwriters and their respective affiliates have provided, and may in the future provide, a variety of these services to the Agency and to persons and entities with relationships with the Agency, for which they received or will receive customary fees and expenses. Under some circumstances, the Underwriters may have certain creditor or other rights against the Agency in connection with such services.

In the ordinary course of their various business activities, the Underwriters and their respective affiliates, officers, directors and employees may purchase, sell or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of the Agency (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with the Agency. The Underwriters and their respective affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments

MUNICIPAL ADVISOR

Stifel, Nicolaus & Company, Incorporated (the "Municipal Advisor") has been employed as independent municipal advisor to the Agency in connection with the issuance of the 2022 Series A and B Bonds. The Municipal Advisor has read and participated in the drafting of certain portions of this Official Statement, but has not audited, authenticated or otherwise verified the accuracy or completeness of the information set forth herein or in any other information made available by the Agency in connection with the offering of the 2022 Series A and B Bonds. The Municipal Advisor makes no guaranty, warranty or other representation respecting the accuracy and completeness of this Official Statement or any other matter related hereto. The Municipal Advisor's fees for services rendered with respect to the sale of the 2022 Series A and B Bonds are, in part, contingent upon the issuance and delivery of the 2022 Series A and B Bonds.

CERTAIN LEGAL MATTERS

The validity of the 2022 Series A and B Bonds and certain other legal matters are subject to the approving opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency. A complete copy of the proposed form of Bond Counsel opinion is contained in APPENDIX I hereto. Copies of such opinion will be provided to the original purchasers without charge.

Certain legal matters with respect to the Agency will be passed upon by Holland & Hart LLP, Salt Lake City, Utah, Counsel to the Agency. Certain legal matters will be passed upon for the Underwriters by their counsel, Gilmore & Bell, P.C., Salt Lake City, Utah.

The Agency has received opinions dated March 30, 1983 from counsel to each of the Power Purchasers to the effect that such Power Purchaser's Power Sales Contract and, if such Power Purchaser is a party to the Excess Power Sales Agreement, the Excess Power Sales Agreement constitute legal, valid and binding obligations of such Power Purchaser, enforceable against such Power Purchaser in accordance with their respective terms. The Agency expects to receive letters from counsel to each of the Power Purchasers confirming such opinions on the date of delivery of the 2022 Series A and B Bonds.

The Agency has received opinions from counsel to each of the Renewal Power Purchasers to the effect that such Renewal Power Purchaser's Renewal Power Sales Contract and, if such Power Purchaser is a party to the Agreement for Sale of Renewal Excess Power, the Agreement for Sale of Renewal Excess Power constitute legal, valid and binding obligations of such Renewal Power Purchaser, enforceable against such Power Purchaser in accordance with their respective terms. Such opinions of counsel were received in January 2017 with respect to the Renewal Power Sales Contracts and May 2017 with respect to the Agreement for Sale of Renewal Excess Power. The Agency expects to receive letters from counsel to each of the Renewal Power Purchasers confirming such opinions on the date of delivery of the 2022 Series A and B Bonds.

INDEPENDENT AUDITORS

The financial statements of the Agency as of and for the fiscal years ended June 30, 2021 and 2020, attached as APPENDIX C to this Official Statement, have been audited by Deloitte & Touche LLP, an independent auditor, as stated in their report appearing therein.

UNAUDITED INTERIM FINANCIAL INFORMATION

Attached as APPENDIX D to this Official Statement is unaudited interim financial information of the Agency as of December 31, 2021 and 2020 and for the six-month periods then ended. Such unaudited financial information should be read in conjunction with the audited financial statements of the Agency as of and for the fiscal years ended June 30, 2021 and 2020, including the notes thereto.

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MISCELLANEOUS

During the initial offering period of the 2022 Series A and B Bonds, copies of the forms of the Power Sales Contracts, the Renewal Power Sales Contracts, the Excess Power Sales Agreement, the Agreement for Sale of Renewal Excess Power, the Resolution, the Construction Management and Operating Agreement, the STS Agreement and the Transmission Service Contracts referred to in "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" above may be obtained from the Agency upon written request. Requests should be addressed to Intermountain Power Agency, 10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095, Attention: Cameron R. Cowan, General Manager.

INTERMOUNTAIN POWER AGENCY

By: /s/ BLAINE J. HAACKE
Chair

By: /s/ CAMERON R. COWAN
General Manager

APPENDIX A

SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION

This Appendix contains a summary of certain provisions of the Resolution, as amended prior to the date of the document to which this Appendix A is attached, including the amendment and restatement of the Resolution provided for in the Second Amended and Restated Power Supply Revenue Bond Resolution adopted by the Agency on November 2, 2021 (the "Second Amended and Restated Resolution"). This summary is not to be considered a full statement of the terms of the Resolution and accordingly is qualified by reference to the full text of the Second Amended and Restated Resolution. Capitalized terms not defined in this Appendix or in the document to which it is attached have the meanings set forth in the Second Amended and Restated Resolution.

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Pledge Effected by the Resolution

Under the Resolution, the Agency has pledged and assigned to the Trustee, for the benefit of the Holders of the Bonds, the Trust Estate, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

In addition, under the Resolution, the Agency has pledged, as additional security for the payment of the principal or sinking fund Redemption Price, if any, of, and interest on, the Bonds of each Additionally Secured Series secured thereby, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution, amounts on deposit in any separate subaccount established in the Debt Service Reserve Account in the Debt Service Fund, including the investments, if any, thereof.

Nature of Obligation

The Resolution provides that the principal and Redemption Price of, and interest on, the Bonds will be payable solely from the Revenues and other funds pledged by the Agency under the Resolution. The Bonds are not an obligation of the State of Utah or any political subdivision thereof, other than the Agency, or any member of the Agency or any Power Purchaser or the Project Manager or Operating Agent and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both is pledged for the payment of the Bonds. No Holder of the Bonds or receiver or trustee in connection with the payment of the Bonds will have the right to compel the State of Utah, any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both to exercise its appropriation or taxing powers.

Application of Revenues

Revenues are pledged by the Resolution to payment of principal and Redemption Price of and interest on the Bonds, subject to the provisions of the Resolution permitting application for other purposes. The Resolution establishes the following Funds and Accounts for the application of Revenues:

Fund	**Held By**
Revenue Fund	Agency
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Indebtedness Fund	Trustee
Subordinated Indebtedness Debt Service Account	
Such other accounts as may be established by the Agency in such Fund	
Self-Insurance Fund	Agency

The Resolution also establishes a Construction Fund, an STS Capital Improvement Construction Fund and one or more Decommissioning Funds.

The Resolution provides that there may be established within any Fund or Account such further accounts or subaccounts as an Authorized Officer may determine, but only if such Authorized Officer files with the Trustee a certificate to the effect that the establishment thereof (a) is for administrative purposes only and (b) will not result in an increase to the Power Purchasers in Monthly Power Costs under the Power Sales Contracts.

The Resolution requires that all Revenues be deposited by the Agency promptly upon receipt thereof to the credit of the Revenue Fund. As soon as practicable in each month, but in any case no later than the last business day of such month, the Agency will withdraw and apply amounts in the Revenue Fund to the following uses in the following order of priority:

1. ***For Operating Expenses***, such sums as are necessary for the payment of reasonable and necessary Operating Expenses for such month.

2. ***To the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund***, (a) for credit to the Debt Service Account, the amount, if any, required so that the balance in said Account equals the Accrued Aggregate Debt Service; *provided, however*, that, for the purposes of computing the amount on deposit in said Account, there will be excluded the amount, if any, set aside in said Account from the proceeds of Bonds or other evidences of indebtedness of the Agency for the payment of interest on Bonds less that amount of such proceeds to be applied in accordance with the Resolution to the payment of interest accrued and unpaid and to accrue on Bonds to the last day of the then current calendar month and (b) for credit to each separate subaccount in the Debt Service Reserve Account, the amount, if any, required so that the balance in each such subaccount equals the Debt Service Reserve Requirement related thereto as of the last day of the then current month (or, if the amount on deposit in the Revenue Fund is not sufficient to make the deposits required to be made as described in this clause (b) with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount on deposit in the Revenue Fund will be applied ratably, in proportion to the amount necessary for deposit into each such subaccount).

The Trustee will apply amounts in the Debt Service Account to the payment of principal of and interest on the Bonds. In addition, the Trustee may, and if directed by the Agency must, apply certain amounts in the Debt Service Account (a) to the purchase or redemption of Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment and (b) to the purchase or redemption of Bonds for which no sinking fund installments have been established prior to the maturity date thereof. The Trustee must pay out of the Debt Service Account the amount required for the redemption of Bonds called for redemption pursuant to sinking fund requirements, or maturing, on any redemption or maturity date.

In the event of the refunding or defeasance of any Bonds, the Trustee will, upon the direction of an Authorized Officer, withdraw from the Debt Service Account all or any portion of the amounts accumulated therein and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on the Bonds being refunded or defeased; *provided, however*, that such withdrawal will not be made unless (a) immediately thereafter the Bonds being refunded or defeased are deemed to have been paid pursuant to the Resolution, and (b) the amount remaining in the Debt Service Account, after giving effect to the issuance of any obligations being issued to refund any Bonds being refunded and the disposition of the proceeds thereof, is not less than the requirement of such Account pursuant to the Resolution.

The Sixty-First Supplemental Power Supply Revenue Bond Resolution adopted by the Agency on April __, 2022 (the "Sixty-First Supplemental Resolution") creates within the Debt Service Reserve Account, for the benefit of (1) the 2022 Series A and B Bonds and (2) all Bonds of any Series hereafter issued, but only to the extent that the Supplemental Resolution authorizing the Bonds of such Series specifies that such Bonds will be an Additionally Secured Series secured thereby, a subaccount designated as the "Initial Subaccount".

The Agency may, with the approval of the Coordinating Committee given as provided the Power Sales Contracts, by Supplemental Resolution, create within the Debt Service Reserve

Account one or more subaccounts, for the benefit of such Series of Bonds as may be specified in, or determined pursuant to, such Supplemental Resolution. In lieu of maintaining moneys or investments in any such subaccount, the Agency at any time may cause to be deposited into such subaccount for the benefit of the Holders of the Bonds of the Additionally Secured Series secured thereby a surety bond, an insurance policy, a letter of credit or any other similar obligation satisfying the requirements set forth in such Supplemental Resolution in an amount (determined as provided in the Resolution) equal to the difference between the Debt Service Reserve Requirement for such subaccount and the sum of moneys or value of Investment Securities then on deposit therein, if any.

If on the last business day of any month the amount in the Debt Service Account is less than the amount required to be in such Account pursuant to the Resolution, the Trustee will apply amounts from each separate subaccount in the Debt Service Reserve Account to the extent necessary to make good the deficiency that exists with respect to the Additionally Secured Series of the Bonds secured thereby.

Whenever the moneys on deposit in any subaccount established in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement related thereto, and after giving effect to any surety bond, insurance policy, letter of credit or other similar obligation that may be credited to such subaccount in accordance with the provisions of the Resolution or the Supplemental Resolution establishing such subaccount, as applicable, such excess will be credited to the Revenue Fund and applied as described in the penultimate paragraph under this caption; *provided, however*, that unless otherwise approved by the Agency and by the Coordinating Committee in the manner provided in the Power Sales Contracts, such excess moneys will be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness.

Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account, is sufficient to pay in full all Outstanding Bonds in accordance with their terms (including principal or applicable sinking fund Redemption Price and interest thereon), the funds on deposit in the Debt Service Reserve Account will be transferred to the Debt Service Account. Any provision of the Resolution to the contrary notwithstanding, so long as there is held in the Debt Service Fund an amount sufficient to pay in full all Outstanding Bonds in accordance with their terms (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits will be required to be made into the Debt Service Reserve Account.

In the event of the refunding or defeasance of any Bonds of an Additionally Secured Series, the Trustee will, upon the direction of an Authorized Officer, withdraw from the separate subaccount in the Debt Service Reserve Account established for the benefit of the Bonds of such Additionally Secured Series all or any portion of the amounts accumulated therein and 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 Bonds being refunded or defeased; *provided, however*, that such withdrawal will not be made unless (A) immediately thereafter, the Bonds being refunded or defeased are deemed to have been paid pursuant to the provisions of the Resolution, and (B) the amount remaining in such separate subaccount in the Debt Service Reserve Account, after giving effect to any surety bond, insurance policy, letter of credit or other similar obligation that may be credited to such subaccount in accordance with the provisions of the Supplemental Resolution establishing such subaccount, and after giving effect to the issuance of any obligations being issued to refund any Bonds being refunded and the disposition of the proceeds thereof, is not less than the Debt Service Reserve Requirement related thereto.

3. ***To the Subordinated Indebtedness Fund***, for deposit in each separate account established in the Subordinated Indebtedness Fund, the respective amount, if any, required so that the balance therein or the amount deposited thereto, as the case may be, equals the amount required to be on deposit therein as of the end of such month or the amount required to be deposited thereto during such month, as applicable, determined as provided in the respective Subordinated Indebtedness Instruments relating to such account and the Subordinated Indebtedness payable therefrom or secured thereby.

The Trustee will apply amounts in each separate account in the Subordinated Indebtedness Fund at the times, in the amounts and to the purposes specified with respect thereto in the Subordinated Indebtedness Instrument relating to such account and the Subordinated Indebtedness payable therefrom or secured thereby. Upon any such withdrawal of any moneys from the Subordinated Indebtedness Fund to be applied to the payment of the principal or sinking fund installments of and interest on (or other amounts due with respect to) any Subordinated Indebtedness or reserves therefor such money will be released and discharged from the lien of the Resolution.

If at any time the amount in the Debt Service Account is less than the requirement of such Account, or the amount in any separate subaccount in the Debt Service Reserve Account is less than the Debt Service Reserve Requirement relating thereto, and there is not on deposit in the Revenue Fund available moneys sufficient to cure either deficiency, then the Trustee will withdraw from the Subordinated Indebtedness Fund and deposit into the Debt Service Account or such separate subaccount(s) in the Debt Service Reserve Account, as the case may be, the amount necessary to make up such deficiency (or, if the amount in said Fund is less than the amount necessary to make up the deficiencies with respect to the Debt Service Account and all of the separate subaccounts in the Debt Service Reserve Account, then the amount in said Fund will be applied first to make up the deficiency in the Debt Service Account, and any balance remaining will be applied ratably to make up the deficiencies with respect to the separate subaccounts in the Debt Service Reserve Account, in proportion to the deficiency in each such subaccount). For the purposes described above, the Trustee will first withdraw amounts from the Subordinated Indebtedness Debt Service Account and, if the amount in said Account is less than the amount necessary to make up the deficiencies with respect to the Debt Service Account and all of the separate subaccounts in the Debt Service Reserve Account, then the Trustee will withdraw from each other account in the Subordinated Indebtedness Fund, ratably in proportion to the respective amounts on deposit therein, the amounts required to make up said deficiencies.

Subject to the provisions of, and to the priorities and limitations and restrictions provided in the Subordinated Indebtedness Instrument securing each issue of Subordinated Indebtedness, amounts in the Subordinated Indebtedness Fund which the Agency at any time determines to be in excess of the requirements of such Fund, may, at the discretion of the Agency, be transferred to the Revenue Fund and applied as described in the penultimate paragraph under this caption; *provided, however*, that unless otherwise approved by the Agency and by the Coordinating Committee in the manner provided in the Power Sales Contracts, such excess moneys will be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness.

4. ***To the Self-Insurance Fund***, one-twelfth (or such greater fraction as may be appropriate if the period is less than twelve months) of the total amount provided for deposit therein during the then Fiscal Year in the current Annual Budget, *provided, however*, that if a deficiency in said Fund is to be restored over a period which extends beyond the Fiscal Year during which such restoration has commenced as described in the proviso to the penultimate paragraph under this item 4, then the deposits in each month to said Fund during such subsequent Fiscal Year will be in the amount determined pursuant to such provision.

Subject to the provisions of the Resolution, upon receipt of a requisition therefor from the Operating Agent under the Construction Management and Operating Agreement in the form prescribed in the Resolution, the Agency will apply amounts in the Self-Insurance Fund to the payment of claims and losses arising from Insurable Risks which are properly payable from the Self-Insurance Fund; *provided, however*, that all such payments will be subject to the provisions of the Resolution relating to the application of insurance proceeds and the reconstruction of the Project.

Notwithstanding anything to the contrary contained in the Resolution, no payments may be made from the Self-Insurance Fund with respect to any claim or loss (a) if such claim or loss is less than $50,000 (or such other amount as the Coordinating Committee may from time to time establish); or (b) if and to the extent that proceeds of insurance or other moneys recoverable as the result of such claim or loss arising from an Insurable Risk that is otherwise payable from such Fund are available to pay such claim or loss.

The Agency may from time to time set aside amounts on deposit in the Self-Insurance Fund as reserves for the payment of claims or losses arising from the occurrence of a particular Insurable Risk or Risks.

If at any time the amount in the Debt Service Account is less than the requirement of such Account, or the amount in any separate subaccount in the Debt Service Reserve Account is less than the Debt Service Reserve Requirement related thereto, and such deficiency has not been cured from available amounts in the Revenue Fund or from transfers from the Subordinated Indebtedness Fund, then the Agency will transfer from the Self-Insurance Fund to the Trustee, for deposit in the Debt Service Account or such separate subaccount(s) in the Debt Service Reserve Account, as the case may be, the amount necessary to make up such deficiency (or, if the amount in said Fund is less than the amount necessary to make up the deficiencies with respect to the Debt Service Account and all of the separate subaccounts in the Debt Service Reserve Account, then the amount in said Fund will be applied first to make up the deficiency in the Debt Service Account, and any balance remaining will be applied ratably to make up the deficiencies with respect to the separate subaccounts in the Debt Service Reserve Account, in proportion to the deficiency in each such subaccount).

Amounts in the Self-Insurance Fund which the Agency at any time determines to be in excess of the requirements of such Fund, such determination to be evidenced by a written statement to this effect signed by an Authorized Officer and confirmed by the Operating Agent under the Construction Management and Operating Agreement, will be applied to make up any deficiencies in the following Funds and Accounts in the following order: the Debt Service Account; and each separate subaccount in the Debt Service Reserve Account; *provided, however*, that if the amount in the Self-Insurance Fund is less than the amount necessary to make up the deficiencies with respect to the Debt Service Account and all of the separate subaccounts in the Debt Service Reserve Account, then the amount in said Fund will be applied first to make up the deficiency in the Debt Service Account, and any balance remaining will be applied ratably to make up the deficiencies with respect to the separate subaccounts in the Debt Service Reserve Account, in proportion to the deficiency in each such subaccount. Any balance of such excess not so applied will be deposited in the Revenue Fund and applied as described in the penultimate paragraph under this caption; *provided, however*, that unless otherwise approved by the Agency and by the Coordinating Committee in the manner provided in the Power Sales Contracts, such excess moneys will be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness.

If at any time the amount on deposit in the Self-Insurance Fund is less than the Self-Insurance Requirement, the Agency will adopt in accordance with the provisions of the Power Sales Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year, which amended Annual Budget will include an amount sufficient to restore the balance in the Self-Insurance Fund to the Self-Insurance Requirement; *provided, however*, that any such deficiency in excess of $5,000,000 (or such other amount as the Coordinating Committee may from time to time establish) will, upon determination of the Agency, be restored in equal monthly payments either (a) during the remainder of the then current Fiscal Year, or (b) by the end of the next succeeding Fiscal Year.

The Agency will at all times maintain policies of insurance which, when combined with amounts on deposit in the Self-Insurance Fund available to pay claims and losses arising from Insurable Risks properly payable from such Fund, will provide funds in amounts sufficient to comply with the requirements of the provisions of the Resolution relating to the maintenance of insurance described under the caption "Insurance" below.

Amounts in the Revenue Fund remaining after the application as described in the foregoing items 1, 2, 3 and 4 may be applied to (a) payments into any separate account or accounts established in the Construction Fund or the STS Capital Improvement Construction Fund for application to the purposes of such account, (b) the costs of Capital Improvements, the payment of extraordinary operation and maintenance costs, the costs of retirement of the Project and contingencies, including payments with respect to the prevention or correction of any unusual loss or damage in connection with the Project or to prevent a loss of revenue therefrom, all to the extent not paid as Operating Expenses or from the proceeds of Bonds or other evidences of indebtedness of the Agency, (c) if any Decommissioning Fund shall have been established pursuant to the Resolution, for credit to each such Fund for application to the purposes thereof and the costs of Capital Improvements, the payment of extraordinary operation and maintenance costs, the costs of retirement of the Project and contingencies, including payments with respect to the prevention or correction of any unusual loss or damage in connection with the Project or to prevent a loss of revenue therefrom, all to the extent not paid as Operating Expenses or from the proceeds of Bonds or other evidences of indebtedness of the Agency and (d) any lawful purpose of the Agency relating to the Project (including, but not limited to, (i) the purchase, redemption or provision for payment of any of the Bonds or Subordinated Indebtedness and (ii) the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts) not otherwise prohibited by the Resolution; *provided, however*, that unless otherwise approved by the Agency and by the Coordinating Committee, such remaining moneys will be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness; and *provided, further*, that none of the remaining moneys will be used for any purpose other than those described in the foregoing items 1, 2, 3, 4 and in the foregoing clause (a) unless all current payments of Operating Expenses and debt service on the Bonds and Subordinated Indebtedness, including all deficiencies in prior payments, if any, have been made in full and unless there does then exist any uncured default by the Agency with respect to any of the covenants, agreements or conditions on its part contained in the Resolution.

If and to the extent provided in a Supplemental Resolution authorizing Bonds of a Series, amounts from the proceeds of such Bonds may be deposited in any separate account in the Revenue Fund and set aside therein as working capital, as reserves for Operating Expenses or as reserves for such other costs or contingencies as may be specified therein. The Agency may also from time to time set aside additional amounts in any separate account in the Revenue Fund as working capital, as a general reserve for Operating Expenses or as reserves for such other costs or contingencies as the Agency may determine (including any reserves established to provide for self-insurance); *provided, however*, that no such amounts will be deposited into any such separate account during any Fiscal Year from Revenues unless provision is made therefor in the Annual Budget for such Fiscal Year; and *provided, further*, that the total amount of any such

general reserve for Operating Expenses accumulated from Revenues held at any time will not exceed 20% of the amount appropriated by the Annual Budget for Operating Expenses for the then current Fiscal Year.

Construction Fund

The Resolution establishes a Construction Fund, to be held by the Agency, into which will be paid amounts required by the provisions of the Resolution and any Supplemental Resolution and, at the option of the Agency, any moneys received for or in connection with the Project by the Agency, unless required to be otherwise applied as provided in the Resolution. In addition, proceeds of insurance for physical loss or damage to the Project, including proceeds of any self-insurance fund, or of contractors' performance bonds pertaining to the period of construction of the Project will be paid into the Construction Fund. Within the Construction Fund, a separate account will be established for any Capital Improvements, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The Agency will pay from the Construction Fund the Cost of Acquisition and Construction of each Capital Improvement, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The completion of construction of any Capital Improvements shall be evidenced by a certificate or certificates of an Authorized Officer, filed with the records of the Agency, stating (i) that such Capital Improvements have been completed in accordance with the plans and specifications applicable thereto and in accordance with the Construction Management and Operating Agreement, (ii) the date of such completion, and (iii) the amount, if any, required in the opinion of the signer or signers for the payment of any remaining part of the Cost of Acquisition and Construction thereof. Upon the filing of such certificate, the balance in the separate account in the Construction Fund established therefor in excess of the amount, if any, stated in such certificate shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts. If subsequent to the filing of such certificate it shall be determined that any amounts specified in such certificate as being required for the payment of any remaining part of the Cost of Acquisition and Construction are no longer so required, such fact shall be evidenced by a certificate or certificates of an Authorized Officer filed with the records of the Agency stating such fact and any amount shown therein as no longer being required shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts.

STS Capital Improvement Construction Fund

The Resolution establishes an STS Capital Improvement Construction Fund, to be held by the Agency, into which will be paid all payments-in-aid of construction received by the Agency (a) in respect

of the STS Renewal Project and (b) in respect of certain Southern Transmission Capital Improvements that SCPPA determines shall be financed by SCPPA under the STS Agreement (including any renewal thereof). Amounts in the STS Capital Improvement Construction Fund will be applied to the Cost of Acquisition and Construction of the STS Renewal Project or of any Southern Transmission Capital Improvements in the manner provided in the Resolution. The STS Capital Improvement Construction Fund is not a part of the Trust Estate and, therefore, is not pledged to the payment of the Bonds.

Certain Conditions to Issuance of Bonds

Bonds will be authenticated by the Trustee pursuant to the Resolution upon compliance with certain requirements and conditions, including the following:

(1) The Trustee has received an Opinion of Counsel to the effect that the Bonds of the Series being issued have been duly and validly authorized, issued and are valid and binding obligations of the Agency and as to certain other matters concerning the Resolution.

(2) The Trustee has received the amount, if any, required by the Supplemental Resolution authorizing the Bonds of such Series to be deposited into the Debt Service Account for the payment of interest on Bonds and, if such Series is an Additionally Secured Series, the amount, if any, necessary for deposit into the separate subaccount in the Debt Service Reserve Account designated therefor so that the amount on deposit in such subaccount equals the Debt Service Reserve Requirement related thereto calculated immediately after the authentication and delivery of such Series of Bonds; *provided, however*, that a Supplemental Resolution establishing a separate subaccount in the Debt Service Reserve Account may provide that, in lieu of maintaining all or a portion of the moneys or investments required to be maintained in such separate subaccount in the Debt Service Reserve Account, there may be credited to such subaccount at any time a surety bond, an insurance policy, a letter of credit or any other similar obligation, or any combination thereof, of the type specified therein, or such amount may be deposited thereafter from Revenues or otherwise, in such manner as may be specified therein.

(3) Except in case of the Refunding Bonds, an Authorized Officer has certified that the Agency is not in default in the performance of its agreements under the Resolution.

Additional Bonds Other than Refunding Bonds

The Agency may issue one or more Series of Bonds (a) for the purpose of paying all or a portion of the Cost of Acquisition and Construction of (i) prior to the Transition Date, any Capital Improvements and (ii) from and after the Transition Date, any Major Capital Improvements (in either such case, including, without limitation, the Gas Repowering or any Alternative Repowering (as such terms are defined in the Original Power Sales Contracts)) or (b) for any other lawful purpose of the Agency in connection with the Project; *provided, however*, that no such Bonds shall be issued pursuant to the foregoing clause (b) unless the Coordinating Committee shall have approved the issuance of such Bonds in the manner provided in the Power Sales Contracts, upon compliance with the following, in addition to the conditions to issuance described above:

(1) In the case of all additional Bonds being issued to finance the cost of Capital Improvements which are determined necessary by the Coordinating Committee under the Power Sales Contracts to keep the Project in good operating condition or to prevent a loss of revenue therefrom, the Trustee has received an opinion of the Operating Agent to such effect.

(2) In the case of all additional Bonds being issued to finance the cost of Capital Improvements either required by any governmental agency having jurisdiction over the Project,

required by the Construction Management and Operating Agreement or required by the Resolution, the Trustee has received an Opinion of Counsel to the effect that such Capital Improvements are either required by such government agency or are an obligation of the Agency arising out of the Construction Management and Operating Agreement or the Resolution, respectively.

The Resolution also provides for the issuance of one or more Series of Bonds for any other lawful purpose of the Agency in connection with the Project; *provided, however*, that no such additional Bonds may be so issued unless (X) the Coordinating Committee has approved the issuance of such Bonds in the manner provided in the Power Sales Contracts and (Y) the Agency by resolution determines (which determination may be based upon such factors as the Agency determines to be appropriate, including, without limitation, the advice of a banking or financial institution serving as a financial advisor to the Agency) that (1) the Agency would have issued Subordinated Indebtedness to finance the costs to be financed with the proceeds of such Bonds and (2) the issuance of such Bonds in lieu of the issuance of such Subordinated Indebtedness does not affect the rights or obligations of the Power Purchasers under the Power Sales Contracts, nor is it to the disadvantage of the Power Purchasers, nor does it result in increased Monthly Power Costs to the Power Purchasers above what would have been the Monthly Power Costs had the Agency so issued such Subordinated Indebtedness.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund, by payment or exchange, any Outstanding Bonds or Subordinated Indebtedness. The issuance of Refunding Bonds to refund Outstanding Bonds is subject to the condition, unless waived by the Coordinating Committee, that an Authorized Officer certify that for the then current and each future Fiscal Year preceding the date of the latest maturity of any Bonds of any Series then Outstanding, the Aggregate Debt Service with respect to the Bonds of all Series to be Outstanding immediately after the date of authentication and delivery of the Refunding Bonds is no greater than that with respect to the Bonds of all Series Outstanding immediately prior to such date.

The Resolution also provides for the issuance of Refunding Bonds of one or more Series to refund, by payment or exchange, any other outstanding Subordinated Indebtedness; *provided, however*, that no such Bonds will be so issued unless (X) the Coordinating Committee has approved the issuance of such Bonds in the manner provided in the Power Sales Contracts and (Y) the Agency by resolution determines (which determination may be based upon such factors as the Agency determines to be appropriate, including, without limitation, the advice of a banking or financial institution serving as a financial advisor to the Agency) that (i) the Agency would have issued Subordinated Indebtedness to refund such other Subordinated Indebtedness and (A) prior to the Transition Date, the issuance of such Bonds in lieu of the issuance of such Subordinated Indebtedness does not affect the rights or obligations of the Power Purchasers under the Power Sales Contracts, nor is it to the disadvantage of the Power Purchasers, nor does it result in increased Monthly Power Costs to the Power Purchasers above what would have been the Monthly Power Costs had the Agency so issued such Subordinated Indebtedness and (B) from and after the Transition Date, the issuance of such Bonds in lieu of the issuance of such Subordinated Indebtedness does not adversely affect the rights or obligations of the Power Purchasers under their respective Renewal Power Sales Contracts.

Special Provisions Relating to Capital Appreciation Bonds and Deferred Income Bonds

For the purposes of (a) receiving payment of the Redemption Price if a Capital Appreciation Bond or a Deferred Income Bond is redeemed prior to maturity, or (b) receiving payment of a Capital Appreciation Bond or a Deferred Income Bond if the principal of all Bonds is declared immediately due and payable following an Event of Default or (c) computing the principal amount of Bonds held by the Holder of a Capital Appreciation Bond or a Deferred Income Bond in giving to the Agency or the Trustee

any notice, consent, request, or demand pursuant to the Resolution for any purpose whatsoever, the principal amount of a Capital Appreciation Bond or a Deferred Income Bond will be deemed to be the amount specified in (or determined in accordance with the provisions of) the Supplemental Resolution authorizing such Capital Appreciation Bond or Deferred Income Bond, as applicable, but in no event will such amount exceed the principal amount thereof plus interest accrued and unpaid thereon to the relevant date of computation.

Credits Against Sinking Fund Installments

If at any time Bonds of any Series and maturity for which Sinking Fund Installments have been established are (a) purchased or redeemed other than from amounts accumulated in the Debt Service Account with respect to any Sinking Fund Installment, or (b) deemed to have been paid pursuant to the provisions of the Resolution and, with respect to such Bonds which have been deemed paid, irrevocable instructions have been given to the Trustee to redeem or purchase (other than pursuant to sinking fund redemption provisions) the same on or prior to the due date of the Sinking Fund Installment to be credited as described in this paragraph, the Agency may, subject to the provisions described in the final sentence of this paragraph, from time to time and at any time determine the portions, if any, of such Bonds so purchased, redeemed or deemed to have been paid and not previously applied as a credit against any Sinking Fund Installment which are to be credited against future Sinking Fund Installments. Such determination will include the amounts of such Bonds to be applied as a credit against such Sinking Fund Installment or Installments and the particular Sinking Fund Installment or Installments against which such Bonds are to be applied as a credit; *provided, however*, that none of such Bonds may be applied as a credit against a Sinking Fund Installment to become due less than 40 days after such determination is made. In any such case, the Sinking Fund Installment so to be credited will be credited in the amount of the sinking fund Redemption Price of the Bonds to be applied thereto as a credit, and the portion of any such Sinking Fund Installment remaining after the deduction of any such amounts credited toward the same (or the original amount of any such Sinking Fund Installment if no such amounts have been credited toward the same) will constitute the unsatisfied balance of such Sinking Fund Installment for the purpose of calculation of Sinking Fund Installments due on a future date. Any such determination by the Agency to apply such Bonds as a credit against future Sinking Fund Installments is approved by the Coordinating Committee in the manner provided in the Power Sales Contracts.

Subordinated Indebtedness

The Agency may issue Subordinated Indebtedness for any purpose of the Agency in connection with the Project, including, without limitation, (i) prior to the Transition Date, the financing of a part of the Cost of Acquisition and Construction of any Capital Improvements or the refunding of any Subordinated Indebtedness or Outstanding Bonds and (ii) from and after the Transition Date, the financing of a part of the Cost of Acquisition and Construction of any Major Capital Improvements or the refunding of any Subordinated Indebtedness or Bonds. Subordinated Indebtedness will be payable out of and may be secured by a pledge of available amounts in the Subordinated Indebtedness Fund; *provided, however*, that any such payment or pledge will be, and will be expressed to be, subordinate and junior in all respects to the pledge and lien created under the Resolution as security for the Bonds; and *provided, further*, that unless the Subordinated Indebtedness Instrument authorizing such Subordinated Indebtedness shall provide that no such certificate shall be required, no such Subordinated Indebtedness shall be so issued except upon receipt by the Trustee of a certificate of an Authorized Officer stating that the Agency is not in default in the performance of any of the covenants, conditions, agreements or provisions contained in the Resolution. No Subordinated Indebtedness may be issued without the approval of the Coordinating Committee of the terms and provisions of the Subordinated Indebtedness Instrument authorizing the issuance or sale of or providing the security for such Subordinated Indebtedness and the contract of purchase pursuant to which such Subordinated Indebtedness is to be sold.

In the event of any insolvency or bankruptcy proceedings, and any receivership, liquidation, reorganization or other similar proceedings in connection therewith, relative to the Agency or to its property, and in the event of any proceedings for voluntary liquidation, dissolution or other winding up of the Agency, whether or not involving insolvency or bankruptcy, the Holders of all Bonds then Outstanding will be entitled to receive payment in full of all principal and interest due on all such Bonds in accordance with the provisions of the Resolution before the holders of the Subordinated Indebtedness are entitled to receive any payment from the Trust Estate on account of principal (and premium, if any) or interest upon the Subordinated Indebtedness.

If any issue of Subordinated Indebtedness is declared due and payable before its expressed maturity because of the occurrence of an event of default (under circumstances when the provisions of the preceding paragraph are not applicable), the Holders of all Bonds Outstanding at the time such Subordinated Indebtedness so becomes due and payable because of such occurrence of such an event of default will be entitled to receive payment in full of all principal and interest on all such Bonds before the holders of the Subordinated Indebtedness are entitled to receive any accelerated payment from the Trust Estate of principal (and premium, if any) or interest upon the Subordinated Indebtedness.

If any Event of Default with respect to the Bonds has occurred and is continuing (under circumstances when the provisions of the third paragraph under this caption are not applicable), the Holders of all Bonds then Outstanding will be entitled to receive payment in full of all principal and interest then due on all such Bonds before the holders of the Subordinated Indebtedness are entitled to receive any payment from the Trust Estate of principal (and premium, if any) or interest upon the Subordinated Indebtedness.

No Holder of a Bond will be prejudiced in its right to enforce subordination of the Subordinated Indebtedness by any act or failure to act on the part of the Agency.

The obligation of the Agency to pay to the holders of the Subordinated Indebtedness the principal thereof and premium, if any, and interest thereon in accordance with its terms are unconditional and absolute. Nothing in the Resolution will prevent the holders of the Subordinated Indebtedness from exercising all remedies otherwise permitted by applicable law or under the Subordinated Indebtedness upon default thereunder, subject to the rights contained in the Resolution of the Holders of Bonds to receive cash, property or securities otherwise payable or deliverable to the holders of the Subordinated Indebtedness; and the Subordinated Indebtedness may provide that, insofar as a trustee or paying agent for the Subordinated Indebtedness is concerned, the foregoing provisions will not prevent the application by such trustee or paying agent of any moneys deposited with such trustee or paying agent for the purpose of the payment of or on account of the principal (and premium, if any) and interest on such Subordinated Indebtedness if such trustee or paying agent did not have knowledge at the time of such application that such payment was prohibited by the foregoing provisions.

Any issue of Subordinated Indebtedness may have such rank or priority with respect to any other issue of Subordinated Indebtedness as may be provided in the Subordinated Indebtedness Instrument securing such issue of Subordinated Indebtedness and may contain such other provisions as are not in conflict with the provisions of the Resolution.

The Trustee will not be deemed to owe any fiduciary duty to the holders of Subordinated Indebtedness and will not be liable to such holders if it mistakenly pays over or transfers to Holders of Bonds, the Agency, or any other person, monies to which any holder of Subordinated Indebtedness is entitled by virtue of the Resolution or otherwise; *provided, however*, that the Trustee will not be relieved from liability for its own negligent action, its own negligent failure to act, or its own willful misconduct. Notwithstanding any of the provisions of the Resolution, the Trustee will not at any time be charged with knowledge of the existence of any facts which would prohibit the making of any payment of monies to or

by the Trustee in respect of Subordinated Indebtedness or of any default in the payment of the principal, premium, if any, or interest on any Subordinated Indebtedness, unless and until the Trustee has received written notice thereof at its principal corporate trust office from the Agency or the holders of at least 10% in principal amount of any class or category of any Subordinated Indebtedness or from any trustee therefor.

Investment of Certain Funds and Accounts

Unless further limited as to maturity by the provisions of a Supplemental Resolution, moneys held in the Funds and Accounts established under the Resolution may be invested and reinvested in Investment Securities which mature or are redeemable at the option of the holder thereof not later than such times as are necessary to provide moneys when needed for payments to be made from such Funds and Accounts. The Trustee will make all such investments of moneys held by it in accordance with instructions received from any Authorized Officer. In making any investment in any Investment Securities with moneys in any Fund or Account established under the Resolution, the Agency or the Trustee, as applicable, may combine such moneys with moneys in any other Fund or Account held by it, but solely for purposes of making such investment in such Investment Securities.

Interest (net of that which represents a return of accrued interest paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds and Accounts, other than the Construction Fund and the STS Capital Improvement Construction Fund, shall be credited to the Revenue Fund. Interest earned on any moneys or investments in a separate account in the Construction Fund shall be held in such account for the purposes thereof. Interest earned on any moneys or investments in the STS Capital Improvement Construction Fund shall be held in such Fund for the purposes thereof. Interest earned on any moneys or investments in any Decommissioning Fund shall be held in such Fund for the purposes thereof.

Encumbrances; Disposition of Properties

The Agency will not issue any bonds, notes, debentures, or other evidences of indebtedness of similar nature, other than the Bonds, payable out of or secured by a pledge or assignment of the Trust Estate or any separate subaccount in the Debt Service Reserve Account, and will not create or cause to be created any lien or charge on the Trust Estate or any separate subaccount in the Debt Service Reserve Account; *provided, however*, that nothing contained in the Resolution will prevent the Agency from issuing, if and to the extent permitted by law, (1) evidences of indebtedness (A) payable out of moneys in the Construction Fund as part of the Cost of Acquisition and Construction of any Capital Improvements or (B) payable out of, or secured by a pledge and assignment of, Revenues to be derived on and after such date as the pledge of the Resolution is discharged and satisfied or (2) Subordinated Indebtedness.

The Agency may, however, acquire, construct or finance through the issuance of its bonds, notes or other evidences of indebtedness any facilities which do not constitute a part of the Project for the purposes of the Resolution and may secure such bonds, notes or other evidences of indebtedness by a mortgage of the facilities so financed or by a pledge of, or other security interest in, the revenues therefrom or any lease or other agreement with respect thereto or any revenues derived from such lease or other agreement; *provided* that such bonds, notes or other evidences of indebtedness will not be payable out of or secured by the Revenues or any Fund held under the Resolution and neither the cost of such facilities nor any expenditure in connection therewith or with the financing thereof will be payable from the Revenues or from any such Fund.

The Agency will not sell, lease or otherwise dispose of, or cause the sale, lease or other disposition of, or permit to be sold, leased or otherwise disposed of, any real or personal properties constituting part of the Project unless such sale, lease or disposal, in the judgment of the Agency, (1) is desirable in the conduct of the business of the Agency relating to the Project and (2) does not materially impair the ability of the

Agency to comply with the rate covenant described under "*Rate Covenant*" below, which judgment will be binding and conclusive on the Agency, the Trustee and the Holders of all Bonds.

Notwithstanding anything to the contrary contained in the Resolution, the Agency will not sell, lease or otherwise dispose of, or cause the sale, lease or other disposition of, or permit to be sold, leased or otherwise disposed of, substantially all of the properties of the Generation Station, the Southern Transmission System and/or the Northern Transmission System unless the Agency has received an Opinion of Counsel to the effect that the Power Sales Contracts as then in effect (and after giving effect to any amendments thereto made in connection therewith) will permit the Agency to comply with its covenants contained in the Resolution following such sale, lease or other disposition.

Rate Covenant

Pursuant to the Resolution, the Agency covenants that it will at all times establish and collect rates and charges for the use of the capability of the Project or the sale of the output, capacity or service of the Project, as are required to provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of the sum of:

(a) 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 credited during such Fiscal Year to each separate subaccount in the Debt Service Reserve Account;

(d) the amount, if any, to be credited during such Fiscal Year to the Subordinated Indebtedness Fund;

(e) the amount, if any, to be credited during such Fiscal Year to the Self-Insurance Fund; and

(f) all other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

Covenants with Respect to Power Sales Contracts and Construction Management and Operating Agreement

Pursuant to the Resolution, the Agency covenants that it will collect and credit to the Revenue Fund all amounts payable to it pursuant to the Power Sales Contracts or payable to it pursuant to any other contract for the use of the capability of the Project or the sale of the output, capacity or service of the Project or any part thereof. The Agency will enforce the material provisions of the Power Sales Contracts and duly perform its material covenants and agreements thereunder. The Agency 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 Power Sales Contracts which will materially reduce the payments required thereunder or which will in any manner materially impair or materially adversely affect the rights of the Agency thereunder or the rights or security of the Holders under the Resolution. Any amendment to the Power Sales Contracts that provides for a reduction in the Project cost and entitlement shares of any one or more Power Purchasers serving loads in the State of Utah, simultaneously with an increase (equal in aggregate amount to the aggregate amount of such reduction(s)) in the Project cost and entitlement shares of any one or more Power Purchasers located in the State of California will not constitute such an amendment, nor will (a) any amendment to the Power Sales Contracts that provides for a reduction in the Project cost and entitlement shares of any one or more Power Purchasers serving loads in the State of Utah, simultaneously with an increase (equal in aggregate

amount to the aggregate amount of such reduction(s)) in the Project cost and entitlement shares of any one or more other Power Purchasers serving loads in the State of Utah or (b) any amendment to the Power Sales Contracts that provides for a reduction in the Project cost and entitlement shares of any one or more Power Purchasers located in the State of California, simultaneously with an increase (equal in aggregate amount to the aggregate amount of such reduction(s)) in the Project cost and entitlement shares of any one or more other Power Purchasers located in the State of California, so long, in the case of (a) and (b) above, as each nationally recognized rating agency then rating the Bonds has confirmed in writing that such amendment will not, in and of itself, result in a reduction, suspension or withdrawal of such rating agency's ratings on the Bonds.

Pursuant to the Resolution, the Agency covenants that it will enforce the material provisions of the Construction Management and Operating Agreement and duly perform its material covenants and agreements thereunder. The Agency 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 Construction Management and Operating Agreement which will in any manner materially impair or materially adversely affect the rights of the Agency thereunder or the rights or security of the Holders under the Resolution. The extension of the term of the Construction Management and Operating Agreement will not constitute such an amendment.

Annual Budget

Pursuant to the Resolution, the Agency covenants that it will adopt and file with the Trustee for each Fiscal Year an Annual Budget prepared in accordance with the provisions of, and in the manner contemplated by, the Power Sales Contracts, setting forth in reasonable detail the estimated Revenues and Operating Expenses and other expenditures of the Project for the Fiscal Year, including provision for any general reserve for Operating Expenses, deposits in any other reserve and the estimated amount to be required during such Fiscal Year for the payment of the costs of Capital Improvements, the payment of extraordinary operation and maintenance costs, the costs of retirement of the Project and contingencies, including payments with respect to the prevention or correction of any unusual loss or damage in connection with the Project or to prevent a loss of revenue therefrom, all to the extent not to be paid as Operating Expenses or from the proceeds of Bonds or other evidences of indebtedness of the Agency, and the requirements, if any, for the amounts estimated to be expended from each Fund and Account established under the Resolution. Such Annual Budget also will set forth such detail with respect to such Revenues, Operating Expenses and other expenditures and such deposits, as is necessary or appropriate so as to comply with the Construction Management and Operating Agreement, the Power Sales Contracts and the Organization Agreement and may set forth such additional material as the Agency may determine. The Agency will at any time, as necessary, adopt in accordance with the provisions of the Power Sales Contracts and file with the Trustee an amended Annual Budget for the remainder of the then current Fiscal Year, if and to the extent required to enable the Agency to comply with its obligations contained in the Resolution.

Insurance

Pursuant to the Resolution, the Agency covenants that it will at all times use its best efforts to keep or cause to be kept the properties of the Project which are of an insurable nature and of the character usually insured by those operating properties similar to the Project insured against loss or damage by fire and from other causes customarily insured against and in such relative amounts and having such deductibles as are usually obtained. The Agency will at all times use its best efforts to maintain or cause to be maintained insurance or reserves against loss or damage from such hazards and risks to the person and property of others as are usually insured or reserved against by those operating properties similar to the properties of the Project.

Any insurance will be in the form of policies or contracts for insurance with insurers of good standing and will be payable to the Agency, *provided, however*, that a fund or funds may be established to

provide for self-insurance by the Agency with respect to the properties of the Project, which fund or funds may (but need not be) established pursuant to a Supplemental Resolution. Any Supplemental Resolution establishing such a fund or funds will set forth the amounts to be included in such fund or funds, the entity to hold such fund or funds and any other matters and things relative to such fund or funds which are not contrary to or inconsistent with the Resolution as theretofore in effect.

Accounts and Reports

Pursuant to the Resolution, the Agency covenants that it will keep or cause to be kept proper and separate books of records and account relating to the Project and each Fund and Account established by the Resolution and relating to costs and charges under the Power Sales Contracts. Such books, together with all other books and papers of the Agency relating to the Project, will at all times be subject to the inspection of the Trustee and the Holders of not less than 5% in principal amount of Bonds then Outstanding.

Pursuant to the Resolution, the Agency covenants that it will annually, (i) prior to the Transition Date, within 90 days after the close of each Fiscal Year, and (ii) from and after the Transition Date, within 120 days after the close of each Fiscal Year, file with the Trustee an annual report for such Fiscal Year, accompanied by an Accountant's Certificate, relating to the Project and including such statements as are required by generally accepted accounting principles applicable to the Agency. Such Accountant's Certificate will state whether or not, to the knowledge of the signer, the Agency is in default with respect to any of the provisions of the Resolution.

Pursuant to the Resolution, the Agency covenants that it will file with the Trustee forthwith upon becoming aware of any Event of Default or default in the performance by the Agency of any covenant, agreement or condition contained in the Resolution, a certificate signed by an Authorized Officer and specifying such Event of Default or default.

The reports, statements and other documents required to be furnished to the Trustee pursuant to provisions of the Resolution will be available for inspection of Holder of the Bonds at the office of the Trustee and will be mailed to each Holder of the Bonds who files a written request therefor with the Agency. The Agency may charge each requesting Holder of the Bonds for such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

Amendments and Supplemental Resolutions

Any of the provisions of the Resolution may be amended by the Agency by a Supplemental Resolution upon the consent of the Holders of not less than a majority in principal amount of (1) the Bonds affected by a particular modification or amendment Outstanding at the time such consent is given, and (2) if the amendment changes the terms of any Sinking Fund Installment, the Bonds of the Series and maturity entitled to such Sinking Fund Installment; excluding, in each case, from such consent, and from the Outstanding Bonds, the Bonds of any specified Series and maturity if such amendment by its terms will not take effect so long as any of such Bonds remain Outstanding. See "Action by Credit Enhancer When Action by Holders of Bonds Required" below. Any such amendment may not permit a change in the terms of redemption or maturity of any installment of interest or make any reduction in principal, Redemption Price or interest rate without the consent of each affected Holder, or reduce the percentages or consents required for a further amendment.

If provided in the Supplemental Resolution authorizing a Series of Bonds to be issued upon original issuance after the adoption of any Supplemental Resolution amending the Resolution in a manner that otherwise requires consent of the Holders, the Holders of such Bonds shall be deemed to have consented to the provisions of such Supplemental Resolution upon the original issuance of such Bonds, and no Holder or subsequent Holder thereof will have the right to revoke such consent.

The Agency may adopt (without the consent of any Holders of the Bonds or the Trustee) Supplemental Resolutions for any one or more of the following purposes:

(a) to close the Resolution against, or impose additional limitations and restrictions upon, issuance of Bonds or other evidences of indebtedness;

(b) to add to the covenants and agreements of the Agency contained in the Resolution;

(c) to add to the limitations and restrictions contained in the Resolution;

(d) to authorize Bonds of a Series and specify matters relative to such Bonds not contrary to or inconsistent with the Resolution;

(e) to provide for the issuance, execution, delivery, authentication, payment, registration, transfer and exchange of Bonds in bearer or coupon form or in uncertificated form, and, in connection therewith, to specify and determine any matters and things relative thereto;

(f) to confirm any pledge under the Resolution of the Revenues or any other moneys, securities or funds;

(g) to authorize the establishment of a fund or funds for self-insurance;

(h) if and to the extent authorized in a Supplemental Resolution authorizing an Additionally Secured Series of Bonds, to specify the qualifications of any provider of a surety bond, insurance policy or letter of credit or other similar obligation for credit to the particular subaccount in the Debt Service Reserve Account securing the Bonds of such Additionally Secured Series;

(i) to modify any of the provisions of the Resolution in any other respect if such modification will be, and be expressed to be, effective only after all Bonds then Outstanding cease to be Outstanding and all Bonds authenticated and delivered after the adoption of such Supplemental Resolution specifically refer to such Supplemental Resolution in the text of such Bonds;

(j) to authorize Subordinated Indebtedness and specify matters relative to such Subordinated Indebtedness not contrary to or inconsistent with the Resolution;

(k) to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in the Resolution; or

(l) to insert such provisions clarifying matters or questions arising under the Resolution as are necessary or desirable; *provided, however*, that no such action will have a material adverse effect on the interests of the Holders of the Bonds.

The Agency may adopt Supplemental Resolutions for the purpose of making any other modification to or amendment of the Resolution which the Trustee in its sole discretion determines will not have a material adverse effect on the interests of Holders of the Bonds, which Supplemental Resolution will be effective upon the consent of the Trustee (without the consent of any Holders of the Bonds).

Trustee; Paying Agents

The Resolution requires the appointment by the Agency of a Trustee and one or more Paying Agents (which may include the Trustee). The Trustee may at any time resign on 60 days' notice. Such resignation will take effect on the date specified in such notice, or, if a successor Trustee has been appointed

by either the Agency or the Holders of the Bonds pursuant to the Resolution prior to such date, such resignation will take effect immediately upon the appointment of such successor.

The Trustee may be removed at any time with or without cause by an instrument or concurrent instruments in writing, filed with the Trustee, and signed by the Holders of a majority in principal amount of the Bonds then Outstanding or their attorneys-in-fact duly authorized, excluding any Bonds held by or for the account of the Agency. In addition, so long as no Event of Default or an event which, with notice or passage of time, or both, would become an Event of Default, has occurred and is continuing, the Trustee may be removed at any time by the Agency with or without cause by resolution of the Agency filed with the Trustee.

If at any time the Trustee resigns or is removed or becomes incapable of acting, or is adjudged a 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, then a successor may be appointed as hereinafter described. If the Trustee has been removed by the Agency, then the Agency will have the exclusive right to appoint such successor. In any other case, the Holders of a majority in principal amount of the Bonds then Outstanding, excluding any Bonds held by or for the account of the Agency, may appoint such successor by an instrument or concurrent instruments in writing signed and acknowledged by such Holders or by their attorneys-in-fact duly authorized and delivered to such successor Trustee, notification thereof being given to the Agency and the predecessor Trustee; *provided, however*, that if no successor Trustee has been appointed by the Holders as aforesaid within 30 days of the date on which the Trustee (1) has mailed notice of its resignation or (2) has become incapable of acting, or has been adjudged a bankrupt or insolvent, or a receiver, liquidator or conservator of the Trustee, or of its property, has been appointed, or any public officer has taken charge or control of the Trustee, or of its property or affairs, then the Agency, subject to the provisions described in the following paragraph, will have the exclusive right to appoint such successor.

If in a proper case no appointment of a successor Trustee is be made pursuant to the foregoing provisions within 45 days after the Trustee has given to the Agency written notice of resignation or after a vacancy in the office of the Trustee has occurred by reason of its inability to act, removal, or for any other reason whatsoever, the Trustee (in the case of its resignation) or the Agency or the Holder of any Bond (in any case) may apply to any court of competent jurisdiction to appoint a successor Trustee. Said court may, after such notice, if any, as such court may deem proper, appoint a successor Trustee.

Each Trustee must be a bank or trust company organized under the laws of any state of the United States or a national banking association having capital stock and surplus aggregating at least $50,000,000, if there be such an entity willing and able to accept appointment.

Pursuant to the Resolution, the Trustee, prior to the occurrence of an Event of Default and after the curing of all Events of Default which may have occurred, undertakes to perform only such duties as are specifically set forth in the Resolution. If an Event of Default has occurred and has not been cured or waived, the Trustee will exercise such of the rights and powers vested in it by the Resolution, and use the same degree of care and skill in their exercise, as a prudent person would exercise or use under the circumstances in the conduct of such person's own affairs. Subject to the above, neither the Trustee nor any Paying Agent will be liable in connection with the performance of its duties under the Resolution except for its own negligence, misconduct or default.

The Agency is required to pay to each Fiduciary reasonable compensation for all services rendered under the Resolution and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its duties under the Resolution. Each Fiduciary has a lien on any and all funds held by it under the Resolution securing its rights to compensation. The Agency also agrees to indemnify and

save each Fiduciary harmless against all liabilities which it may incur in the exercise and performance of its powers and duties under the Resolution, and which are not due to its negligence, misconduct or default.

Redemption of Bonds

Any call for redemption of Bonds at the election or direction of the Agency (a) may be revoked by the Agency at its option and (b) will cease to be effective if, on the date fixed for redemption, there are not sufficient moneys available to pay the Redemption Price of, and interest on, the Bonds (or portions thereof) so called for redemption.

Defeasance

The pledge and assignment of the Trust Estate and each separate subaccount in the Debt Service Reserve Account, and all covenants, agreements and other obligations of the Agency to the Holders of the Bonds under the Resolution, will cease, terminate and become void and be discharged and satisfied whenever the principal, Redemption Price, if applicable, and interest due or to become due on all Bonds have been paid in full. Notwithstanding the foregoing, upon such discharge and satisfaction (a) the provisions relating to the establishment, maintenance and operation of the various funds and accounts established under the Resolution, (b) the pledges of the amounts on deposit in the Subordinated Indebtedness Fund as may from time to time be available therefor (including the investments held as a part of such Fund) created pursuant to the Subordinated Indebtedness Instruments authorizing the issuance or incurrence of such Indebtedness, (c) the Trustee's obligations with respect to the Subordinated Indebtedness Fund, (d) the rights, privileges, protections, immunities and indemnities afforded to the Trustee in Article X of the Resolution and (e) all other provisions of the Resolution necessary or desirable to give effect to the foregoing, shall remain in full force and effect so long as any Subordinated Indebtedness remains outstanding.

Bonds or interest installments will be deemed to have been paid for the purpose of the defeasance referred to above in this paragraph if on the maturity or redemption date thereof moneys have been set aside and held in trust by the Paying Agents for such payment. In addition, any Bonds will be deemed to have been so paid prior to the maturity or redemption date thereof (a) if the Agency has satisfied all of the conditions precedent to such Bonds being so deemed to have been paid set forth in the Supplemental Resolution authorizing the Series of which such Bonds are a part or (b) upon compliance with the following provisions: (1) in the case of Bonds to be redeemed prior to maturity, the Agency has given to the Trustee instructions accepted in writing by the Trustee to give notice of redemption therefor, (2) there have been deposited with the Trustee either moneys in an amount which will be sufficient, or Defeasance Securities the principal of and the interest on which, when due, will provide moneys which, together with any moneys also deposited, will be sufficient to pay when due the principal or Redemption Price, if applicable, and interest due or to become due on such Bonds on or prior to the redemption date or maturity date thereof, as the case may be, and (3) in the case of Bonds that are not to be redeemed or paid at maturity within the next 60 days, the Agency has given the Trustee instructions to give, as soon as practicable, by first-class mail, postage prepaid, notice to the Holders of such Bonds that the above deposit has been made with the Trustee and that such Bonds are deemed to be paid and stating the maturity or redemption date upon which moneys are to be available to pay the principal or Redemption Price, if applicable, on such Bonds.

For purposes of determining whether Variable Interest Rate Bonds are deemed to have been paid prior to the maturity or redemption date thereof, as the case may be, by the deposit of moneys, or Defeasance Securities and moneys, if any, in accordance with the provisions described in the preceding paragraph, the interest to come due on such Variable Interest Rate Bonds on or prior to the maturity date or redemption date thereof, as the case may be, will be calculated at the Maximum Interest Rate with respect thereto; *provided, however*, that if on any date, as a result of such Variable Interest Rate Bonds having borne interest at less than such Maximum Interest Rate for any period, the total amount of moneys and Defeasance

Securities on deposit with the Trustee for the payment of interest on such Variable Interest Rate Bonds is in excess of the total amount which would have been required to be deposited with the Trustee on such date in respect of such Variable Interest Rate Bonds in order to satisfy such provisions, the Trustee will, if requested by the Agency, pay the amount of such excess to the Agency free and clear of any trust, lien, pledge or assignment securing the Bonds or otherwise existing under the Resolution.

Events of Default and Remedies

Events of Default specified in the Resolution include failure to pay principal or Redemption Price of any Bond when due; failure to pay any interest installment on any Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; default for 120 days after written notice thereof from the Trustee or the Holders of not less than 10% in principal amount of the Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Resolution or in the Bonds; and certain events of bankruptcy or insolvency. Upon the happening of any such Event of Default the Trustee or the Holders of not less than 25% in principal amount of the Bonds then Outstanding may declare the principal of and accrued interest on all Bonds then Outstanding due and payable (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon occurrence of any Event of Default which has not been remedied, the Agency will, if demanded by the 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 Resolution, and (2) pay over or cause to be paid over to the Trustee (a) forthwith, all moneys, securities and funds held by the Agency in any Fund under the Resolution and (b) as received, all Revenues.

The Trustee will apply all moneys, securities, funds and Revenues, other than amounts on deposit in any separate subaccount in the Debt Service Reserve Account, received during the continuance of an Event of Default as follows and in the following order:

(a) to the payment of reasonable and proper charges, expenses and liabilities of the Trustee and other Fiduciaries,

(b) to the payment of reasonable and necessary Operating Expenses and costs of reasonable renewals, repairs and replacements of the Project, and

(c) (i) unless the principal of all of the Bonds has become or have been declared due and payable, *first*, to the payment to the persons entitled thereto of all installments of interest then due in the order of the maturity of such installments, together with accrued and unpaid interest on the Bonds theretofore called for redemption, and, if the amount available are not sufficient to pay in full any such installment or installments maturing 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, *second*, to the payment to the persons entitled thereto of the unpaid principal or Redemption Price of any Bonds which have become due, whether at maturity or by call for redemption, in the order of their due dates, and, if the amount available is not sufficient to pay in full all the Bonds due on any date, then to the payment thereof ratably, according to the amounts of principal or Redemption Price due on such date, to the persons entitled thereto, without any discrimination or preference; or (ii) if the principal of all of the Bonds have become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon the Bonds without preference or priority of principal over interest or of interest over principal or of any installment of interest over any other installment of interest, or of any such Bond over any other such Bond, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference except as to any difference in the respective rates of interest specified in such Bonds.

During the continuance of an Event of Default, and following the application of moneys, securities, funds and Revenues received by the Trustee as described in the preceding paragraph, the Trustee will apply all amounts on deposit in each separate subaccount in the Debt Service Reserve Account as follows and in the following order:

(a) unless the principal of all of the Bonds have become or have been declared due and payable, *first*, to the payment to the persons entitled thereto of all installments of interest then due on the Bonds of each Additionally Secured Series secured by such separate subaccount in the order of the maturity of such installments, together with accrued and unpaid interest on the Bonds of such Additionally Secured Series theretofore called for redemption, and, if the amount available is not sufficient to pay in full any such installment or installments maturing 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 *second*, to the payment to the persons entitled thereto of the unpaid principal or sinking fund Redemption Price of any Bonds of such Additionally Secured Series which have become due, whether at maturity or by call for redemption, in the order of their due dates, and, if the amount available is not sufficient to pay in full all such Bonds due on any date, then to the payment thereof ratably, according to the amounts of principal or sinking fund Redemption Price due on such date, to the persons entitled thereto, without any discrimination or preference; or

(b) if the principal of all of the Bonds has become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon the Bonds of each Additionally Secured Series secured by such separate subaccount without preference or priority of principal over interest or of interest over principal or of any installment of interest over any other installment of interest, or of any such Bond over any other such Bond, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference except as to any difference in the respective rates of interest specified in such Bonds.

In addition, following the occurrence and continuance of any Event of Default, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the Project.

If an Event of Default has occurred and has not been remedied the Trustee may, or on request of the Holders of not less than 25% in principal amount of Bonds then Outstanding must, proceed to protect and enforce its rights and the rights of the Holders of the Bonds under the Resolution forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Resolution or in aid of the execution of any power granted in the Resolution or any remedy granted under the Act, or for an accounting against the Agency, or in the enforcement of any other legal or equitable right, as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Resolution. The Trustee may, and upon the request of the Holders of a majority in principal amount of the Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Resolution or to preserve or protect the interests of the Trustee and of the Holders of the Bonds.

No Holder of any Bond will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Resolution or the execution of any trust under the Resolution or for any remedy under the Resolution, unless (1) such Holder previously has given the Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Bonds then Outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity to exercise its powers and institute such suit, action or proceeding, (3) there have been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (4) the Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer

of indemnity. The Resolution provides that nothing therein or in the Bonds affects or impairs the Agency's obligation to pay the Bonds and interest thereon when due or the right of any Holder of the Bonds to enforce such payment of its Bond.

The Holders of not less than a majority in principal amount of Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability or would be unjustly prejudicial to Holders of Bonds not parties to such direction.

See "Action by Credit Enhancer When Action by Holders of Bonds Required" below.

Notice of Default

Notice of the occurrence of any Event of Default will be given to each Holder of any Bonds then Outstanding at its address, if any, appearing in the Registry Books.

Unclaimed Moneys

Any moneys held by a Fiduciary in trust for the payment of any of the Bonds or any interest thereon which remain unclaimed for two years after the date when such Bonds or such interest have become due and payable, either at their stated maturity dates or by call for redemption, will, at the written request of the Agency and after meeting certain publication requirements, be repaid to the Agency, and the Fiduciary will thereupon be released and discharged with respect thereto and the Holders of the Bonds shall look only to the Agency for the payment of such Bonds or such interest.

Action by Credit Enhancer When Action by Holders of Bonds Required

Except as otherwise provided in a Supplemental Resolution authorizing Bonds for which Credit Enhancement is being provided, if not in default in respect of any of its obligations with respect to Credit Enhancement for such Bonds, the Credit Enhancer for, and not the actual Holders of, such Bonds, for which such Credit Enhancement is being provided, will be deemed to be the Holder of Bonds as to which it is the Credit Enhancer at all times for the purpose of (a) giving any approval or consent to the effectiveness of any Supplemental Resolution or any amendment, change or modification of the Resolution that requires the written approval or consent of Holders of Bonds; *provided, however*, that the foregoing will not apply to any change in the terms of redemption or maturity of the principal of any Outstanding Bond or of any installment of interest thereon or a reduction in the principal amount or the Redemption Price thereof or in the rate of interest thereon, or will reduce the percentages or otherwise affect the classes of Bonds the consent of the Holders of which is required to effect any such modification or amendment, or will change or modify any of the rights or obligations of any Fiduciary without its written assent thereto and (b) giving any approval or consent, exercising any remedies or taking any other action in accordance with the provisions of the Resolution relating to Events of Default and remedies.

Definitions

Accrued Aggregate Debt Service means, as of any date of calculation, an amount equal to the sum of the amounts of accrued Debt Service with respect to all Series, calculating the accrued Debt Service with respect to each Series at an amount equal to the sum of (a) interest on the Bonds of such Series accrued and unpaid and to accrue to the end of the then current calendar month, and (b) Principal Installments due and unpaid and that portion of the Principal Installments for such Series next due which would have accrued (if

deemed to accrue in the manner set forth in the definition of Debt Service) to the end of such calendar month; *provided, however*, that there will be excluded from the calculation of Accrued Aggregate Debt Service for any period the principal of and/or interest (including, without limitation, interest on any Capital Appreciation Bond or Deferred Income Bond) on any Bond that, in accordance with the Supplemental Resolution authorizing the Series of which such Bond is a part, will not be deemed to accrue during such period for purposes of this definition.

Additionally Secured Series means any Series of Bonds for which the payment of the principal or sinking fund Redemption Price, if any, of, and interest on, the Bonds of such Series is secured, in addition to the pledge created in favor of all of the Bonds, by amounts on deposit in a separate subaccount to be designated therefor in the Debt Service Reserve Account.

Adjusted Aggregate Debt Service means, as of any date of calculation and with respect to any period, the Aggregate Debt Service during such period for all Series of Bonds; *provided, however*, that in computing such Aggregate Debt Service, any particular Variable Interest Rate Bonds will be deemed to bear at all times to the maturity thereof the Estimated Average Interest Rate applicable thereto.

Aggregate Debt Service for any period means, as of any date of calculation, the sum of the amounts of Debt Service for such period with respect to all Series of Bonds.

Bond or *Bonds* means any bond or bonds, as the case may be, authenticated and delivered under and pursuant to the Resolution.

Book Entry Bond means a Bond authorized to be issued to, and issued to and, except as provided in the Resolution, restricted to being registered in the name of, a Securities Depository for the participants in such Securities Depository or the beneficial owners of such Bond.

Capital Appreciation Bonds means any Bonds issued under the Resolution as to which interest is (a) compounded periodically on dates that are specified in the Supplemental Resolution authorizing such Capital Appreciation Bonds and (b) payable only at maturity or upon earlier redemption or other payment thereof pursuant to the Resolution or such Supplemental Resolution; *provided, however*, that the interest on such Bonds will not be compounded more frequently than semi-annually unless the Agency by resolution determines (which determination may be based upon such factors as the Agency determines to be appropriate, including, without limitation, the advice of any banking or financial institution serving as a financial advisor to the Agency) that (X) the Agency would have issued such Bonds having interest compounded semi-annually and (Y) the issuance of such Bonds having interest compounded more frequently than semi-annually in lieu of the issuance of such Bonds having interest compounded semi-annually (i) prior to the Transition Date, does not affect the rights or obligations of the Power Purchasers under the Original Power Sales Contracts, nor is it to the disadvantage of such Power Purchasers, nor does it result in increased Monthly Power Costs to such Power Purchasers above what would have been the Monthly Power Costs had the Agency so issued such Bonds having interest compounded semi-annually and (ii) from and after the Transition Date, does not adversely affect the rights or obligations of the Power Purchasers under their respective Renewal Power Sales Contracts.

Capital Improvements has the meaning assigned to such term in the applicable Power Sales Contracts.

Coordinating Committee (a) prior to the Transition Date, means, collectively, (i) the Committee by that name established pursuant to the Original Power Sales Contracts, and (ii) the Renewal Contract Coordinating Committee (as defined in the Renewal Power Sales Contracts) with respect to the functions contemplated for the Renewal Contract Coordinating Committee under the Original Power Sales Contracts

and the Renewal Power Sales Contracts; and (b) commencing on the Transition Date, means the Renewal Contract Coordinating Committee.

Cost of Acquisition and Construction (a) prior to the Transition Date, has the meaning assigned to such term in the Original Power Sales Contracts; and (b) from and after the Transition Date, means the Capital Improvement Acquisition and Construction Costs (as defined in the Renewal Power Sales Contracts).

Credit Enhancement means, with respect to any Bonds, an insurance policy, letter of credit, surety bond or other similar obligation pursuant to which the issuer thereof is unconditionally obligated to pay when due the principal of and interest on such Bonds, whether on a "standby" or "direct-pay" basis.

Credit Enhancer means any person or entity which, pursuant to the Supplemental Resolution authorizing the Bonds of a particular Series, is designated as a Credit Enhancer and which provides Credit Enhancement for the Bonds of such Series or any maturity or maturities thereof.

Debt Service for any period means, as of any date of calculation and with respect to any Series of Bonds, an amount equal to the sum of (i) interest accruing during such period on Bonds of such Series, except to the extent that such interest is to be paid from deposits in the Debt Service Account made from proceeds of Bonds or other evidences of indebtedness of the Agency and (ii) that portion of each Principal Installment for such Series which would accrue during such period if such Principal Installment were deemed to accrue daily in equal amounts from the next preceding Principal Installment due date for such Series (or, if there is no such preceding Principal Installment due date, from a date one year preceding the due date of such Principal Installment or from the date of issuance of the Bonds of such Series, whichever date is later) ; *provided, however*, that there will be excluded from the calculation of Debt Service for any period the principal of and/or interest (including, without limitation, interest on any Capital Appreciation Bond or Deferred Income Bond) on any Bond that, in accordance with the Supplemental Resolution authorizing the Series of which such Bond is a part, is not deemed to accrue during such period for purposes of this definition. Such interest and Principal Installments for such Series will be calculated on the assumption that no Bonds of such Series Outstanding at the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof.

Debt Service Reserve Requirement means, with respect to each subaccount, if any, in the Debt Service Reserve Account in the Debt Service Fund, the amount specified in the Supplemental Resolution pursuant to which such subaccount shall be established.

Decommissioning Fund means each Fund established pursuant to the Resolution to provide for payment of the costs of decommissioning, retirement or disposal of facilities of the Project (including, without limitation, the Retirement Reserve Fund required to be established by the Agency as of the Transition Date pursuant to Section 22.1 of the Renewal Power Sales Contracts, which shall include a separate account for each Project Component (as defined in the Renewal Power Sales Contracts)).

Defeasance Securities means, unless otherwise provided with respect to any Bonds in the Supplemental Resolution authorizing the Series of which such Bonds are a part, any of the following securities:

(a) any bonds or other obligations which constitute direct obligations of, or as to principal and interest are unconditionally guaranteed by, the United States of America, including obligations of any agency or corporation which has been or may hereafter be created pursuant to an Act of Congress as an agency or instrumentality of the United States of America to the extent unconditionally guaranteed by the United States of America, in each such case, which are not subject to redemption prior to their maturity other than at the option of the holder thereof or as to

which an irrevocable notice of redemption of such securities on a specified redemption date has been given and such securities are not otherwise subject to redemption prior to such specified date other than at the option of the holder thereof;

(b) 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 (1) which are not callable prior to maturity, or which have been duly called for redemption by the obligor on a date or dates specified and as to which irrevocable instructions have been given to a trustee, escrow agent or other fiduciary in respect of such bonds or other obligations by the obligor to give due notice of such redemption on such date or dates, which date or dates also will be specified in such instructions, (2) which are secured as to principal and interest and redemption premium, if any, by a fund consisting only of cash or bonds or other obligations of the character described in clause (a) above, 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 redemption date or dates specified in the irrevocable instructions referred to in subclause (1) of this clause (b), as appropriate, (3) as to which the principal of and interest on the bonds and obligations of the character described in clause (a) above on deposit in such fund along with any cash on deposit in such fund are sufficient to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this clause (b) on the maturity date or dates thereof or on the redemption date or dates specified in the irrevocable instructions referred to in subclause (1) of this clause (b), as appropriate and (4) which at the time of their purchase under the Resolution are rated in the highest whole rating category by a nationally recognized rating agency;

(c) obligations of any state of the United States of America or any political subdivision thereof or any agency or instrumentality of any state or political subdivision which are not callable for redemption prior to maturity, or which have been duly called for redemption by the obligor on a date or dates specified and as to which irrevocable instructions have been given to a trustee, escrow agent or other fiduciary in respect of such obligations by the obligor to give due notice of such redemption on such date or dates, which date or dates also will be specified in such instructions, and which at the time of their purchase under the Resolution are rated in the highest whole rating category by two nationally recognized rating agencies; and

(d) certificates that evidence ownership of the right to payments of principal and/or interest on obligations described in the foregoing clauses (a), (b) and (c) of this definition, *provided* that such obligations are held in trust by a bank or trust company or a national banking association authorized to exercise corporate trust powers and subject to supervision or examination by federal, state, territorial or District of Columbia authority and having a combined capital, surplus and undivided profits of not less than $50,000,000, in any such case, which are not subject to redemption prior to their maturity other than at the option of the holder thereof or as to which an irrevocable notice of redemption of such obligations on a specified redemption date has been given and such obligations are not otherwise subject to redemption prior to such specified date other than at the option of the holder thereof.

Deferred Income Bonds means any Bonds issued under the Resolution as to which interest accruing prior to a date specified in the Supplemental Resolution authorizing such Deferred Income Bonds is (a) compounded periodically on dates specified in such Supplemental Resolution and (b) payable only at maturity or upon earlier redemption or other payment thereof pursuant to the Resolution or such Supplemental Resolution; *provided however*, that the interest on such Bonds will not be compounded more frequently than semi-annually unless the Agency by resolution determines (which determination may be based upon such factors as the Agency determines to be appropriate, including, without limitation, the advice of any banking or financial institution serving as a financial advisor to the Agency) that (X) the Agency would have issued such Bonds having interest compounded semi-annually and (Y) the issuance of

such Bonds having interest compounded more frequently than semi-annually in lieu of the issuance of such Bonds having interest compounded semi-annually (i) prior to the Transition Date, does not affect the rights or obligations of the Power Purchasers under the Original Power Sales Contracts, nor is it to the disadvantage of such Power Purchasers, nor does it result in increased Monthly Power Costs (as defined in the Original Power Sales Contracts) to such Power Purchasers above what would have been the Monthly Power Costs had the Agency so issued such Bonds having interest compounded semi-annually and (ii) from and after the Transition Date, does not adversely affect the rights or obligations of the Power Purchasers under their respective Renewal Power Sales Contracts.

Estimated Average Interest Rate means, as to any Variable Interest Rate Bonds, the true interest cost for such Bonds, as estimated by the Agency on the date of authorization of such Bonds based upon such factors as the Agency determines to be appropriate, including, without limitation, the advice of any banking or financial institution serving as a financial advisor to the Agency.

Excess Liability Insurance means, as to any Insurable Risk the claims or losses for which are payable from time to time from amounts on deposit in the Self-Insurance Fund, the policy or policies of insurance at any time in effect to provide coverage for the payment of claims or losses in excess of the amounts payable from the Self-Insurance Fund arising from such Risk.

Fiscal Year for the period (a) prior to the Transition Date, shall have the meaning set forth in the Original Power Sales Contracts; and (b) from and after the Transition Date, shall have the meaning set forth in the Renewal Power Sales Contracts.

Insurable Risk means each and every risk for which the Agency is required to maintain insurance or reserves against loss pursuant to the provisions of the Resolution and the Power Sales Contracts.

Investment Securities means and includes any securities, obligations or investments that, at the time, (a) are permitted by Utah law for investment of the Agency's funds and (b) are permitted by the investment policy then in effect adopted by the Agency's Board of Directors and approved by the Coordinating Committee in the manner provided in the Power Sales Contracts.

Maximum Interest Rate means, with respect to any particular Variable Interest Rate Bonds, a numerical rate of interest which will be set forth in the Supplemental Resolution authorizing such Bonds, that will be the maximum rate of interest such Bonds may at any time bear.

Minimum Interest Rate means, with respect to any particular Variable Interest Rate Bonds, a numerical rate of interest which may (but need not) be set forth in the Supplemental Resolution authorizing such Bonds, that will be the minimum rate of interest such Bonds may at any time bear.

Operating Expenses means (i) all of the Agency's costs and other expenses in connection with the operation and maintenance of the Project in accordance with Prudent Utility Practice and ordinary repairs, replacements and reconstruction of the Project which do not entail the acquisition and installation of a unit of property (as generally prescribed by the Federal Energy Regulatory Commission or its successor), including all costs of producing and delivering electric power and energy from the Project and payments into reserves in the Revenue Fund for items of Operating Expenses the payment of which is not immediately required, and includes, without limiting the generality of the foregoing, fuel costs, rents, administrative and general expenses, engineering expenses, legal and financial advisory expenses, required payments to pension, retirement, health and hospitalization funds, insurance premiums, any taxes or payments in lieu of taxes pursuant to the Act or otherwise pursuant to law and payments required under the Construction Management and Operating Agreement which are to be applied pursuant to the terms thereof to the payment (or reimbursement for the payment) of such costs and expenses, (ii) any other current expenses or obligations required to be paid by the Agency under the provisions of the Resolution or by law, all to the

extent properly allocable to the Project, or required to be incurred under or in connection with the performance of the Power Sales Contracts, (iii) the fees, expenses and indemnities of the Trustee and Paying Agents, and (iv) the fees, expenses and indemnities of any trustee or paying agents with respect to Subordinated Indebtedness. Operating Expenses will not include any debt service, any costs or expenses for new construction or any allowance for depreciation or amortization. For the avoidance of doubt and without limiting the generality of the forgoing, Operating Expenses shall include (a) all amounts payable by the Agency to SCPPA in respect of debt service on SCPPA's bonds, notes or other evidences of indebtedness as provided in the STS Agreement and (b) (i) prior to the Transition Date, costs of Capital Improvements which are not to be financed by proceeds of Bonds or Subordinated Indebtedness and (ii) from and after the Transition Date, costs of Ordinary Capital Improvements.

Original Power Sales Contracts means the contracts described in clause (a) of the definition of Power Sales Contracts.

Outstanding, when used with reference to Bonds, means, as of any date, Bonds theretofore or thereupon being authenticated and delivered under the Resolution except:

(i) Bonds cancelled (or, in the case of Book Entry Bonds, to the extent provided in the Resolution, portions thereof deemed to have been cancelled) by the Trustee at or prior to such date;

(ii) Bonds (or portions of Bonds) for the payment or redemption of which moneys, equal to the principal amount or Redemption Price thereof, as the case may be, with interest to the date of maturity or redemption date, are held in trust under the Resolution and set aside for such payment or redemption (whether at or prior to the maturity or redemption date), and for which, in the case of Bonds to be redeemed, notice of such redemption has been given or provision made therefor;

(iii) Bonds in lieu of or in substitution for which other Bonds have been authenticated and delivered pursuant to the Resolution; and

(iv) Bonds (or portions of Bonds) deemed to have been paid for purposes of determining defeasance.

Power Purchasers means (a) prior to the Transition Date, the thirty-five suppliers of electric energy (other than the Agency) that are parties to the contracts described in clause (a) of the definition of Power Sales Contracts contained, together in each case with their successors or assigns and (b) from and after the Transition Date, the thirty suppliers of electric energy (other than the Agency) that are parties to the contracts described in clause (b) of such definition of Power Sales Contracts, together in each case with their successors or assigns. In furtherance of the foregoing definition of Power Purchasers and the definition of Power Sales Contracts, (x) based upon the Agency's and the Coordinating Committee's belief that the statements in clauses (i) and (ii) below were the intention or consistent with the intention of the parties to the Original Power Sales Contracts, and of the Coordinating Committee, (i) the fact that any Transition Project Indebtedness (as such term is defined in the Original Power Sales Contracts) shall remain outstanding after June 15, 2027 shall not result, or be deemed to have resulted, in an extension, pursuant to Section 26.1 of the Original Power Sales Contracts, of the date upon which such Contracts terminate and (ii) any extension pursuant to Section 26.1 of the Original Power Sales Contracts of the date upon which an Original Power Sales Contract terminates shall require, and be deemed to require, a written amendment between the Agency and the Power Purchaser that is the party to such Original Power Sales Contract which amendment complies with Section 26.2 of such Original Power Sales Contract and provides in Section 23 of such Original Power Sales Contract for a date other than June 15, 2027, which is the date that is expressly provided in such Section 23, and (y) any reference in the Resolution to the termination date of such Original Power Sales Contracts shall be and be deemed to refer to June 15, 2027, unless such Original Power Sales Contracts shall have terminated as permitted thereby prior to such date.

Power Sales Contracts means (a) prior to the Transition Date, (i) the several Power Sales Contracts for the sale of the power and energy of the Project entered into between the Agency and the Power Purchasers described in clause (a) of the definition of Power Purchasers, as the same have been or hereafter may be amended or supplemented in accordance with their terms and the terms of the Resolution and (ii) the Renewal Power Sales Contracts to the extent that the Renewal Power Sales Contracts impose obligations, grant rights or otherwise govern the Project during such period and (b) from and after the Transition Date, the several Renewal Power Sales Contracts for the sale of the power and energy of the Project entered into between the Agency and the Power Purchasers described in clause (b) of such definition of Power Purchasers, as the same have been or hereafter may be amended or supplemented in accordance with their terms and the terms of the Resolution.

Principal Installment means, as of any date of calculation and with respect to any Series, so long as any Bonds thereof are Outstanding, (i) the principal amount of Bonds of such Series due on a certain future date for which no Sinking Fund Installments have been established, or (ii) the unsatisfied balance of any Sinking Fund Installments due on a certain future date for Bonds of such Series, plus the amount of the sinking fund redemption premiums, if any, which would be applicable upon redemption of such 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 Bonds of such Series, the sum of the above, as applicable.

Project has the meaning set forth in the Original Power Sales Contracts prior to the Transition Date and the meaning set forth in the Renewal Power Sales Contracts on and after the Transition Date.

Prudent Utility Practice shall have the meaning set forth in the Original Power Sales Contracts prior to the Transition Date and the meaning set forth in the Renewal Power Sales Contracts on and after the Transition Date.

Renewal Power Sales Contracts means the contracts described in clause (b) of the definition of Power Sales Contracts.

Revenues means (i) all revenues, income, rents and receipts derived or to be derived by the Agency from or attributable to the ownership and operation of the Project, including all revenues attributable to the Project or to the payment of the costs thereof received or to be received by the Agency under the Power Sales Contracts or under any other contract for the sale of power, energy, transmission or other service from the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services, output or capacity thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, and (iii) interest received or to be received on any moneys or securities (other than in the Construction Fund or the STS Capital Improvement Construction Fund) held pursuant to the Resolution and required to be paid into the Revenue Fund.

Securities Depository means, with respect to a Book Entry Bond, the person, firm, association or corporation specified in the Supplemental Resolution authorizing the Bonds of the Series of which such Book Entry Bond is a part to serve as the securities depository for such Book Entry Bond, or its nominee, and its successor or successors and any other person, firm, association or corporation which may at any time be substituted in its place pursuant to the Resolution or such Supplemental Resolution.

Self-Insurance Requirement means (a) the sum of (1) one hundred and fifty percent (150%) of the largest Self-Insured Retention and (2) reserves, if any, set aside in the Self-Insurance Fund, or (b) such other amount as the Coordinating Committee approves from time to time.

Self-Insured Retention means, at any time and with regard to any Insurable Risk the claims or losses for which are payable from time to time from amounts on deposit in the Self-Insurance Fund, an amount

equal to the greatest amount of any such claim or loss payable from such Fund for which Excess Liability Insurance is not available to pay such claim or loss.

Sinking Fund Installment means, with respect to any Series of Bonds, an amount so designated which is required by a Supplemental Resolution authorizing the Bonds of such Series to be credited to the Debt Service Account by a specified date for application (on or prior to the due date of such Sinking Fund Installment and pursuant to the Resolution) to the retirement by purchase, redemption or payment at maturity of a portion of the Bonds of a particular maturity of such Series equal in principal amount to such Sinking Fund Installment.

Southern Transmission Capital Improvement shall have the meaning assigned to such term in the Renewal Power Sales Contracts.

Southern Transmission System shall have the meaning set forth in the Original Power Sales Contracts prior to the Transition Date and the meaning set forth in the Renewal Power Sales Contracts on and after the Transition Date.

STS Agreement means the Southern Transmission System Agreement, dated as of May 1, 1983, between the Agency and SCPPA, as heretofore amended and as hereafter amended or renewed.

STS Capital Improvement Construction Fund means the Fund by that name established by the Resolution.

STS Renewal Project means certain additions and improvements to and renewals of the Southern Transmission System described in Appendix C to the Original Power Sales Contracts to provide for an extension of the useful life of said Southern Transmission System, as more particularly described in the STS Agreement.

Subordinated Indebtedness means any bond, note or other evidence of indebtedness which is expressly made subordinate and junior in right of payment to the Bonds and which complies with the provisions of the Resolution. Any such Subordinated Indebtedness will not, except as otherwise specifically provided in the Resolution, be nor be deemed to be Bonds for purposes of the Resolution.

Subordinated Indebtedness Instrument means the resolution, indenture or other instrument, including any Supplemental Resolution, providing for the issuance of, and securing, any issue of Subordinated Indebtedness.

Trust Estate means (a) the proceeds of the sale of the Bonds, (b) the Revenues, and (c) all Funds and Accounts established by the Resolution (other than (X) the Debt Service Reserve Account in the Debt Service Fund, (Y) any Decommissioning Fund which may be established pursuant to the Resolution and (Z) the STS Capital Improvement Construction Fund,), including the investments and investment income, if any, thereof.

Variable Interest Rate means a variable interest rate to be borne by a Series of Bonds or any one or more maturities within a Series of Bonds. The method of computing such variable interest rate will be specified in the Supplemental Resolution authorizing such Series of Bonds and will be based on (i) a percentage or percentages or other function of an objectively determinable interest rate or rates (*e.g.*, the prime lending rate) or a function of such objectively determinable interest rate or rates which may be in effect from time to time or at a particular time or times; *provided, however*, that such variable interest rate will be subject to a Maximum Interest Rate and may be subject to a Minimum Interest Rate and that there may be an initial rate specified, in each case as provided in such Supplemental Resolution or (ii) a stated interest rate that may be changed from time to time as provided in the Supplemental Resolution authorizing

such Series. Such Supplemental Resolution will also specify either (i) the particular period or periods of time for which each value of such variable interest rate will remain in effect or (ii) the time or times upon which any change in such variable interest rate will become effective.

Variable Interest Rate Bonds means Bonds which bear a Variable Interest Rate.

Year means any period of twelve consecutive months.

Proposed Amendments to the Resolution

The Fiftieth Supplemental Power Supply Revenue Bond Resolution adopted by the Agency on August 28, 1998 (the "Fiftieth Supplemental Resolution") provided for the making of certain amendments to the Resolution. The various amendments to the Resolution contained in the Fiftieth Supplemental Resolution will become effective on the date (if any) on which, among other things, all of the Original Power Purchasers consent in writing thereto. Since the Agency does not expect such amendments to become effective, such amendments are not described herein.

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APPENDIX B

SUMMARIES OF CERTAIN PROVISIONS OF AGREEMENTS

This Appendix contains summaries of certain provisions of the Project agreements. These summaries are not to be considered full statements of the terms of the respective documents and accordingly are qualified by reference to such respective documents and subject to the full text thereof. Except as expressly provided herein, capitalized terms have the respective meanings set forth in the document to which this Appendix is attached.

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SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS

The following is a summary of certain provisions of the Power Sales Contracts, as amended (including the amendments effected by the Amendatory Power Sales Contracts and the Power Sales Contracts Amendments), entered into between the Agency and each of the Power Purchasers. Except as described in this summary, all of the Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Power Sales Contracts and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in this section of this Appendix captioned "Summary of Certain Provisions of the Power Sales Contracts" have the meanings set forth in the document to which this Appendix is attached or set forth in the Power Sales Contracts.

Entitlement to Capacity

Each Power Purchaser is entitled to receive under its Power Sales Contract capacity and energy from the Generation Station up to its Generation Entitlement Share, as specified in its Power Sales Contract, of the available capacity of the Generation Station. A Power Purchaser may arrange to dispose of capacity or energy from the Project to which it is entitled, but any such arrangements will not affect its obligations under its Power Sales Contract. Each Power 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 Power 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 Power Purchasers' Generation Entitlement Shares to be delivered at the Points of Delivery on the Southern Transmission System and the Northern Transmission System, respectively. Power Purchasers having unused entitlement to transmission capacity may agree to allow other Power Purchasers to use such entitlement except that no Power 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 (as such term is defined in the Power Sales Contracts; the term "Bonds" as defined in the Power Sales Contracts and as used in this summary means both Bonds (as defined in the Resolution) and Subordinated Indebtedness).

Nature of Obligation

Each Power Purchaser which is a municipally owned electric system is obligated to make the payments required under its 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 Power Purchaser has covenanted to include in its annual power system budget for each fiscal year during the term of its 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 Power Sales Contract. The Power Sales Contracts constitute a general obligation of each Power Purchaser which is not a municipally owned electric system. The Power Purchasers' obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective Power Sales Contracts are not subject to reduction or offset whether or not the Project is completed, operating or operable or its output (and as a result, the capacity available to each of the Power Purchasers) is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the Power Purchasers' payment obligations under the Power Sales Contracts are not conditioned upon the performance by the Agency or any other party (including any other Power Purchaser) of contractual or other obligations and are not subject to any reduction or offset in the event of any default by the Agency in the performance of its obligations under the Power Sales Contracts.

Term

The term of each 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.

Required Payments

For a discussion on Monthly Power Costs and the payment obligations of the respective Power Purchasers with respect thereto, see the discussion under the caption "SECURITY AND SOURCES OF PAYMENT FOR SENIOR INDEBTEDNESS AND SUBORDINATED INDEBTEDNESS" in the document to which this Appendix is attached.

Rate Covenants of Municipal Power Purchasers

Each Power Purchaser which is a municipally owned electric system has covenanted in its 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 the Agency all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

Coordinating Committee

The Power Sales Contracts provide for the establishment of a Coordinating Committee composed of representatives of the Power Purchasers and the Agency which is to (a) provide liaison among the Agency and the Power 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 the Project 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 the Project and revisions to the description of the Project contained in the Power Sales Contracts, (d) approve all consultants or advisors on financial matters, including bond counsel, that may be retained by the Agency, (e) make recommendations to the Agency concerning (and, in certain specified situations, approve) 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 Power Sales Contracts and the Construction Management and Operating Agreement. No action by the Coordinating Committee pursuant to its authority under the Power Sales Contracts or otherwise shall require the Agency to act in a manner inconsistent with, or refrain from acting as required by, the Resolution or any applicable licenses, permits or regulatory provisions.

Any action taken by the Coordinating Committee shall require an affirmative decision of representatives of Power Purchasers having Voting Rights aggregating at least 80 percent. If the 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 (see "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT – Coordinating Committee" in this Appendix). The term Voting Rights means at any particular time with respect to a Power Purchaser, such Power Purchaser's Generation Entitlement Share in effect at such time under its Power Sales Contract.

Restrictions on Disposition

A Power 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 Power Purchaser assigns its interest under its Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Power Purchaser under the 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, (iii) an independent and qualified engineer of national reputation opines that the purchaser or lessee is reasonably able to charge and collect rates and charges as required under the Power Sales Contract, and (iv) it is determined by the Agency that the disposition will not adversely affect the value of such Power Sales Contract as security for the Bonds or affect the eligibility for tax exempt status of Bonds issued by the Agency. In addition, a Power Purchaser may not sell, assign or otherwise dispose of any portion of its Generation Entitlement Share or the capacity rights granted under its Power Sales Contract in the Northern Transmission System or the Southern Transmission System except if it is determined by the Agency that the disposition will not adversely affect the eligibility for exemption from federal income taxes of interest on the Bonds.

Defaults and Remedies

The failure of a Power Purchaser to perform any of its obligations, including the obligation to make required payments under its Power Sales Contract, will constitute a default. In the event of a default or inability to perform by a Power Purchaser under its Power Sales Contract, the Agency may proceed to enforce the Power 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 Power Sales Contract remains unpaid when due, the Agency may, upon 120 days' written notice to the Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities described below, the discontinuance of delivery of capacity and energy to, and the use of Project facilities by, a defaulting Power Purchaser by the Agency will not reduce the obligation of such Power Purchaser to make payments under its Power Sales Contract.

In the event the delivery of capacity and energy to, and use of Project facilities by, a Power Purchaser in default is discontinued, the Agency shall transfer to all other Power Purchasers which are not in default and which so request, a pro rata portion of the defaulting Power Purchaser's rights to delivery of capacity and energy and use of Project facilities. In the case of such a transfer, the Power Purchasers accepting additional rights to delivery of capacity and energy and use of Project facilities shall assume the defaulting Power 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 Power Purchaser's rights to delivery of capacity and energy and use of Project facilities are transferred to non-defaulting Power Purchasers, the Agency shall, to the extent possible, dispose of such remaining rights on the best terms readily available in accordance with procedures formulated by the 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. The obligation of the defaulting Power Purchaser to the Agency shall be reduced to the extent that the Agency receives payments with respect to the rights of such Power Purchaser which are transferred.

Termination or Amendment

As long as any Bonds issued under the Resolution are outstanding or until provision has been made for the payment of any Bonds outstanding in accordance with the Resolution, the 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 or which will impair or adversely affect the rights

of the holders of the Bonds. Each Power Sales Contract also provides that the Agency may not, without the consent of each of the Power Purchasers, amend or supplement the Resolution (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Power Purchasers under the Power Sales Contracts or to be to the disadvantage of the Power Purchasers or to result in increased Monthly Power Costs to the Power Purchasers.

Contracts Subject to Resolution

It has been recognized by the Power Purchasers in the Power Sales Contracts that the Agency, in financing, acquiring, constructing and operating the Project, must comply with the requirements of the Resolution and all licenses, permits and regulatory approvals necessary therefor, and the Power Purchasers have therefore agreed that the Power Sales Contracts are subject to the provisions of the Resolution and such licenses, permits and approvals.

Payments-In-Aid of Construction

If requested by the Agency, one or more Power 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 an 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 the covenants under the Resolution with respect to such Fund, all such deposits will be used by the Agency 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 the Agency's ownership of such facility or of the Project or any of the rights and obligations of the Agency or the Power Purchasers under the Power Sales Contracts.

Use and Disposition of Certain Facilities

In recognition of the fact that the Project consists of certain rights, properties and facilities that could be used in connection with the construction and operation at the Project site of additional generating units or transmission facilities, the Agency may, with the approval of the 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 Project 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 the Project or adversely affect the eligibility for federal income tax exemption of the interest payable on the Bonds.

Expansion of Southern Transmission System

Any proposal for a major expansion of the Southern Transmission System is to be initiated by the Coordinating Committee. Such proposal must comply with the Project agreements and must provide that, subject to compliance with Utah law, the Power Purchasers having entitlement to the Southern Transmission System under their respective Power Sales Contracts will have the right to participate in the additional capacity of such expansion in proportion to their respective entitlement shares. Upon approval of any such proposal by the Agency and the Coordinating Committee, the Agency will use its best efforts to proceed with the development of such expansion.

Certain Interconnection Agreements

The Power Purchasers agree that the Agency may comply with the requirements of the Mona Interconnection Agreement or other agreements approved by the Coordinating Committee with respect to furnishing start up and black start power from the Project. All amounts received by the Agency for furnishing such service shall be credited against Monthly Power Costs.

Transmission Service

Subject to contractual rights with respect to the Northern Transmission System, the Agency may schedule the unused capacity of such System for transmission service for other utilities. All amounts received by the Agency for furnishing such service shall be credited against Monthly Power Costs.

Insurance Provisions

The Agency will take reasonable and prudent steps to maintain properly designed and properly underwritten Project property and casualty insurance programs during the construction phase of the Project and will design and arrange underwriting for property and casualty insurance programs for the operating phase of the Project. The Agency will make every economically feasible effort to incorporate into the operation phase of the Project 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 the Project.

Gas Repowering

The Agency has agreed with each of the Power Purchasers to undertake the Gas Repowering. Once the Gas Repowering has achieved commercial operation, the Generation Station will consist of two natural gas combined cycle power blocks with an approximate combined net generation capability of 840 MW, together with related equipment and facilities of the Gas Repowering, and the Gas Repowering will supply the electric power generation of the Project in replacement of the then existing generating units and related facilities and properties. The Power Sales Contracts obligate the Agency to achieve commercial operation of the Gas Repowering by July 1, 2025.

The Agency is required to fund the Gas Repowering using Transition Project Indebtedness, unless otherwise approved by the Coordinating Committee. The costs of the Gas Repowering include the Retirement Costs related to the Retired Generation and Related Facilities and Properties.

The Power Sales Contracts also provide that in the event the Gas Repowering is not undertaken as provided in the Power Sales Contracts, and there is no Transition Project Indebtedness outstanding, the Project will consist of transmission facilities with sufficient generation capacity to support such transmission facilities. The entitlements to such facilities would be sold to the Power Purchasers who elect to renew their entitlements in the Project pursuant to a transmission services agreement. The California Renewal Purchasers would be offered 100% of the entitlements in the Southern Transmission System and 60% of the entitlements in the Northern Transmission System. The Utah Renewal Purchasers would be offered 40% of the entitlements in the Northern Transmission System. The term of the Power Sales Contracts would be extended to the earlier of the completion of decommissioning and retirement of the facilities not necessary to maintain and support such transmission facilities and January 1, 2032. In that event, the Renewal Power Sales Contracts and the Agreement for Sale of Renewal Excess Power would terminate.

POWER PURCHASERS' COST AND ENTITLEMENT SHARES

The following table sets forth the Generation Cost and Entitlement Shares of each of the Power Purchasers for the output and services of the generating units and the cost and entitlement shares of those Power Purchasers taking the output and services of the transmission systems included in the Project.

	Generation Cost Share and Entitlement Share	Northern Transmission Cost Share and Entitlement Share[1]	Southern Transmission Cost Share and Entitlement Share[2]
CALIFORNIA PURCHASERS			
Los Angeles Department of Water and Power	48.617%	.000%	59.534%
City of Anaheim	13.225	.000	17.647
City of Riverside	7.617	.000	10.164
City of Pasadena	4.409	.000	5.883
City of Burbank	3.371	.000	4.498
City of Glendale	1.704	.000	2.274
Total—6 California Purchasers	78.943%	.000%	100.000%
UTAH MUNICIPAL PURCHASERS			
Murray City	4.000%	18.996%	.000%
Logan City	2.469	11.725	.000
The City of Bountiful	1.695	8.050	.000
Kaysville City	.739	3.510	.000
Heber Light & Power Company	.627	2.978	.000
Hyrum City	.551	2.617	.000
Fillmore City	.512	2.431	.000
The City of Ephraim	.503	2.389	.000
Lehi City	.430	2.042	.000
Beaver City	.413	1.961	.000
Parowan City	.364	1.729	.000
Price	.361	1.714	.000
Mount Pleasant	.357	1.695	.000
City of Enterprise	.199	.945	.000
Morgan City	.190	.902	.000
City of Hurricane	.147	.698	.000
Monroe City	.130	.617	.000
The City of Fairview	.120	.570	.000
Spring City	.060	.285	.000
Town of Holden	.048	.228	.000
Town of Meadow	.045	.214	.000
Kanosh	.040	.190	.000
Town of Oak City	.040	.190	.000
Total—23 Utah Municipal Purchasers	14.040%	66.676%	.000%
COOPERATIVE PURCHASERS			
Moon Lake Electric Association, Inc.	2.000%	9.498%	.000%
Mt. Wheeler Power, Inc.	1.786	8.482	.000
Dixie-Escalante Rural Electric Association, Inc	1.534	7.285	.000
Garkane Power Association, Inc	1.267	6.017	.000
Bridger Valley Electric Association	.230	1.092	.000
Flowell Electric Association	.200	.950	.000
Total—6 Cooperative Purchasers	7.017%	33.324%	.000
			.000
Total—35 Power Purchasers	100.000%	100.000%	100.000%

(footnotes on following page)

(footnotes from previous page)

1 The Northern Transmission Cost and Entitlement Shares of each Power Purchaser having a point of delivery on the Northern Transmission System are determined by dividing such Power Purchaser's Generation Entitlement Share by the total of the Generation Entitlement Shares to be delivered on the Northern Transmission System.

2 The Southern Transmission Cost and Entitlement Shares of each Power Purchaser having a point of delivery on the Southern Transmission System are determined by dividing such Power Purchaser's Generation Entitlement Share by the total of the Generation Entitlement Shares to be delivered on the Southern Transmission System except with respect to 4% Generation Entitlement Share that was allocated to the Department pursuant to the Power Sales Contracts Amendments (the Department's Generation Entitlement Share increased by such 4%, but such 4% was omitted from both the dividend and the divisor for purposes of calculating Southern Transmission Cost and Entitlement Shares of the Power Purchasers having a point of delivery on the Southern Transmission System).

SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS

The following is a summary of certain provisions of the Renewal Power Sales Contracts, as revised to reflect changes to Appendix C to the Renewal Power sales Contracts and the termination of or reduction in Generation Entitlement Share of certain Renewal Power Purchasers under their respective Renewal Power Sales Contracts, entered into between the Agency and each of the Renewal Power Purchasers. Except as described in this summary, all of the Renewal Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Renewal Power Sales Contracts and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in this section of this Appendix captioned "Summary of Certain Provisions of the Renewal Power Sales Contracts" have the meanings set forth in the document to which this Appendix is attached or set forth in the Renewal Power Sales Contracts. Unless otherwise expressly stated, the terms of the Renewal Power Sales Contracts described in this Appendix apply from and after the Transition Date.

Entitlement to Capacity

Each Renewal Power Purchaser is entitled to receive under its Renewal Power Sales Contract capacity and energy from the Generation Station up to its Generation Entitlement Share, as specified in its Renewal Power Sales Contract, of the available capacity of the Generation Station. A Renewal Power Purchaser may arrange to dispose of capacity or energy from the Project to which it is entitled, but any such arrangements will not affect its obligations under its Renewal Power Sales Contract. Each Renewal Power 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 Renewal Power 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 Renewal Power Purchasers' Generation Entitlement Shares to be delivered at the Points of Delivery on the Southern Transmission System and the Northern Transmission System, respectively. Renewal Power Purchasers having unused entitlement to transmission capacity may agree to allow other Renewal Power Purchasers to use such entitlement except that no Renewal Power 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 Debt Instruments (as such term is defined in the Renewal Power Sales Contracts; the term "Debt Instruments" as defined in the Renewal Power Sales Contracts and as used in this summary means both Bonds (as defined in the Resolution) and Subordinated Indebtedness).

Nature of Obligation

Each Renewal Power Purchaser is obligated to make the payments required under its Renewal 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 Renewal Power Purchaser has covenanted to include in its annual power system budget for each fiscal year during the term of its Renewal 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 Renewal Power Sales Contract. The Renewal Power Purchasers' obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective Renewal Power Sales Contracts are not subject to reduction or offset whether or not the Project is operating or operable or its output (and as a result, the capacity available to each of the Renewal Power Purchasers) is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the Renewal Power Purchasers' payment obligations under the Renewal Power Sales Contracts are not conditioned upon the performance by the Agency or any other party (including any other Renewal Power Purchaser) of contractual or other obligations and are not subject to any reduction or offset in the event of any default by the Agency in the performance of its obligations under the Renewal Power Sales Contracts.

Term

The term of each Renewal Power Sales Contract has commenced and will end on June 16, 2077, unless terminated sooner in accordance with the provisions for termination or amendment described below. Although the term of each Renewal Power Sales Contract has commenced, the Renewal Power Sales Contracts will not govern, generally, the purchase and sale of the capacity and output of the Project until June 16, 2027 (the "Transition Date"), which is the day following the scheduled termination of the Power Sales Contracts.

Required Payments

For a discussion on Monthly Power Costs and the payment obligations of the respective Renewal Power Purchasers with respect thereto, see the discussion under the caption "SECURITY AND SOURCES OF PAYMENT FOR THE 2022 SERIES A AND B BONDS" in the document to which this Appendix is attached.

Rate Covenants of Renewal Power Purchasers

Each Renewal Power Purchaser has covenanted in its Renewal 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 and other available funds, are sufficient to enable it to pay to the Agency all amounts payable under its Renewal Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

Renewal Contract Coordinating Committee

The Renewal Power Sales Contracts provide for the establishment of a Renewal Contract Coordinating Committee composed of representatives of the Renewal Power Purchasers and the Agency which is to (a) provide liaison among the Agency and the Renewal Power 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 the Project 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 the Project and revisions to the description of the Project contained in the Renewal Power Sales Contracts, (d) approve all consultants or advisors on financial matters, including bond counsel, that may be retained by the Agency, (e) make recommendations to the Agency concerning (and, in certain specified situations, approve) 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 Renewal Power Sales Contracts and the Construction Management and Operating Agreement. No action by the Renewal Contract Coordinating Committee pursuant to its authority under the Renewal Power Sales Contracts or otherwise shall require the Agency to act in a manner inconsistent with, or refrain from acting as required by, the Resolution or any applicable licenses, permits or regulatory provisions.

The Renewal Power Sales Contracts required the election of representatives to the Renewal Contract Coordinating Committee within 30 days of the full subscription by the Renewal Power Purchasers for Generation Entitlement Shares under the Renewal Power Sales Contracts. Prior to the Transition Date, the Renewal Contract Coordinating Committee's authority is limited to considering matters related to Transition Project Indebtedness and other matters requiring Renewal Contract Coordinating Committee

approval prior to the Transition Date pursuant to the Power Sales Contracts or the Renewal Power Sales Contracts and to receive financial statements and operating reports provided to the Coordinating Committee in the ordinary course of business. The Renewal Contract Coordinating Committee's approval is required for the issuance of Transition Project Indebtedness for purposes other than financing the Gas Repowering (so long as the Transition Project Indebtedness satisfies the requirements in the Renewal Power Sales Contracts related to Substantially Equal Debt Service).

Any action taken by the Renewal Contract Coordinating Committee shall require an affirmative decision of representatives of Renewal Power Purchasers having Voting Rights aggregating at least 80 percent. To the extent that any of the Fuel Management Practices and Procedures modifies the payment responsibility of any of the Renewal Power Purchasers for costs of Project Fuel acquisition or the costs of Project Fuel transmission or transportation, as then determined under the Renewal Power Sales Contracts, then such modification would require affirmation by Renewal Contract Coordinating Committee representatives of Purchasers having Voting Rights (as defined in the Renewal Power Sales Contracts) equal to 100 percent.

If the Renewal Contract 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 Agency and the Department (as Project Manager and Operating Agent) have negotiated a form of Construction Management and Operating Agreement that addresses time limits with respect to the Renewal Contract Coordinating Committee. That form has been submitted to the Department's governing bodies for approval. The term Voting Rights means at any particular time with respect to a Renewal Power Purchaser, such Renewal Power Purchaser's Generation Entitlement Share in effect at such time under its Renewal Power Sales Contract.

Restrictions on Disposition

A Renewal Power 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 Renewal Power Purchaser assigns its interest under its Renewal Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Renewal Power Purchaser under the Renewal Power Sales Contract, (ii) the senior debt of the purchaser or lessee is rated in one of the three highest categories by at least one nationally-recognized bond rating agency, (iii) an independent and qualified engineer of national reputation opines that the purchaser or lessee is reasonably able to charge and collect rates and charges as required under the Renewal Power Sales Contract, and (iv) it is determined by the Agency that the disposition will not adversely affect the value of such Renewal Power Sales Contract as security for the Debt Instruments or affect the eligibility for tax exempt status of Debt Instruments issued by the Agency. In addition, a Renewal Power Purchaser may not sell, assign or otherwise dispose of any portion of its Generation Entitlement Share or the capacity rights granted under its Renewal Power Sales Contract in the Northern Transmission System or the Southern Transmission System except if it is determined by the Agency that the disposition will not adversely affect the eligibility for exemption from federal income taxes of interest on the Debt Instruments.

The Renewal Power Sales Contracts provide that except in connection with a disposition of a Renewal Power Purchaser's electric system in compliance with the requirements of the Renewal Power Sales Contracts, no disposition of a Purchaser's rights under its Renewal Power Sales Contract releases such Purchaser from its obligations under its Renewal Power Sales Contract.

Defaults and Remedies

The failure of a Renewal Power Purchaser to perform any of its obligations, including the obligation to make required payments under its Renewal Power Sales Contract, will constitute a default. In the event of a default or inability to perform by a Renewal Power Purchaser under its Renewal Power Sales Contract, the Agency may proceed to enforce the Renewal Power 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 Renewal Power Sales Contract remains unpaid when due, the Agency may, upon 120 days' written notice to the Renewal Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Renewal Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Renewal Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities described below, the discontinuance of delivery of capacity and energy to, and the use of Project facilities by, a defaulting Renewal Power Purchaser by the Agency will not reduce the obligation of such Renewal Power Purchaser to make payments under its Renewal Power Sales Contract.

In the event the delivery of capacity and energy to, and use of Project facilities by, a Renewal Power Purchaser in default is discontinued, the Agency shall transfer to all other Renewal Power Purchasers which are not in default and which so request, a pro rata portion of the defaulting Renewal Power Purchaser's rights to delivery of capacity and energy and use of Project facilities. In the case of such a transfer, the Renewal Power Purchasers accepting additional rights to delivery of capacity and energy and use of Project facilities shall assume the defaulting Renewal Power 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 Renewal Power Purchaser's rights to delivery of capacity and energy and use of Project facilities are transferred to non-defaulting Renewal Power Purchasers, the Agency shall, to the extent possible, dispose of such remaining rights on the best terms readily available in accordance with procedures formulated by the Renewal Contract 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. The obligation of the defaulting Renewal Power Purchaser to the Agency shall be reduced to the extent that the Agency receives payments with respect to the rights of such Renewal Power Purchaser which are transferred.

Termination or Amendment

As long as any Debt Instruments issued under the Resolution are outstanding or until provision has been made for the payment of any Debt Instruments outstanding in accordance with the Resolution, the Renewal 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 Debt Instruments or which will impair or adversely affect the rights of the holders of the Debt Instruments. Each Renewal Power Sales Contract also provides that the Agency may not, without the consent of each of the Renewal Power Purchasers, amend or supplement the Resolution (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Renewal Power Purchasers under the Renewal Power Sales Contracts or to be to the disadvantage of the Renewal Power Purchasers or to result in increased Monthly Power Costs to the Renewal Power Purchasers.

Contracts Subject to Resolution

It has been recognized by the Renewal Power Purchasers in the Renewal Power Sales Contracts that the Agency, in financing, acquiring, constructing and operating the Project, must comply with the requirements of the Resolution and all licenses, permits and regulatory approvals necessary therefor, and the Renewal Power Purchasers have therefore agreed that the Renewal Power Sales Contracts are subject to the provisions of the Resolution and such licenses, permits and approvals.

Payments-In-Aid of Construction

If requested by the Agency, one or more Renewal Power 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 an 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 the covenants under the Resolution with respect to such Fund, all such deposits will be used by the Agency for the payment of the Capital Improvement Acquisition and Construction Costs with respect to such facility. The payments-in-aid of construction will not change or otherwise affect the Agency's ownership of such facility or of the Project or any of the rights and obligations of the Agency or the Renewal Power Purchasers under the Renewal Power Sales Contracts.

Use and Disposition of Certain Facilities

In recognition of the fact that the Project consists of certain rights, properties and facilities that could be used in connection with the construction and operation at the Project site of additional generating units or transmission facilities, the Agency may, with the approval of the Renewal Contract 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 Project 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 the Project or adversely affect the eligibility for federal income tax exemption of the interest payable on the Bonds.

Expansion of Southern Transmission System or Northern Transmission System

Any proposal for a major expansion of the Southern Transmission System or the Northern Transmission System is to be initiated by the Renewal Contract Coordinating Committee. Such proposal must comply with the applicable Agency agreements entered into in accordance with the terms of the Renewal Power Sales Contracts and must provide that, subject to compliance with Utah law, the Renewal Power Purchasers having entitlement to the Southern Transmission System or the Northern Transmission System, respectively, under their respective Renewal Power Sales Contracts will have the right to participate in the additional capacity of such expansion in proportion to their respective entitlement shares in such transmission system. Upon approval of any such proposal by the Agency and the Renewal Contract Coordinating Committee, the Agency will use its best efforts to proceed with the development of such expansion.

Certain Interconnection Agreements

The Renewal Power Purchasers agree that the Agency may comply with the requirements of any agreement approved by the Coordinating Committee or the Renewal Contract Coordinating Committee with respect to furnishing start-up and black start power from the Project. All amounts received by the Agency for furnishing such service shall be credited against Monthly Power Costs.

Transmission Service

Renewal Power Purchasers agree that, subject to contractual rights with respect to the Northern Transmission System, the Agency may schedule the unused capacity of such System for transmission service for other utilities. All amounts received by the Agency for furnishing such service shall be credited against Monthly Power Costs.

Insurance Provisions

The Agency will take reasonable and prudent steps to maintain properly designed and properly underwritten Project property and casualty insurance programs for each Project Component during the Operational Period and for each Capital Improvement during the construction phase of such Capital Improvement. The Agency will make every economically feasible effort to incorporate into the Project property insurance program extra-expense and business interruption coverage tied to all perils covered by the property insurance program, automobile liability insurance, insurance against risk of liability under environmental laws and regulations and insurance covering losses resulting from failure or interruption of the Project Fuel supply for the Project.

RENEWAL POWER PURCHASERS' COST AND ENTITLEMENT SHARES

The following table sets forth the Generation Cost and Entitlement Shares of each of the Renewal Power Purchasers for the output and services of the generating units and the cost and entitlement shares of those Renewal Power Purchasers taking the output and services of the transmission systems included in the Project.

	Generation Cost Share and Entitlement Share	Northern Transmission Cost Share and Entitlement Share[1]	Southern Transmission Cost Share and Entitlement Share[2]
CALIFORNIA PURCHASERS			
Los Angeles Department of Water and Power	71.442%	.000%	90.500%
City of Burbank	3.334	.000	4.222
City of Glendale	4.167	.000	5.278
Total—3 California Purchasers	74.943%	.000%	100.000%
UTAH MUNICIPAL PURCHASERS			
Murray City	4.036%	19.1670%	.000%
Logan City	2.491	11.8298	.000
The City of Bountiful	1.711	8.1256	.000
Kaysville City	.746	3.5428	.000
Heber Light & Power Company	.633	3.0061	.000
Hyrum City	.551	2.6167	.000
Fillmore City	.517	2.4552	.000
The City of Ephraim	.508	2.4125	.000
Lehi City	.434	2.0611	.000
Beaver City	.413	1.9613	.000
Parowan City	.364	1.7286	.000
Price	.364	1.7286	.000
Mount Pleasant	.357	1.6954	.000
City of Enterprise	.199	.9451	.000
Morgan City	.192	.9118	.000
City of Hurricane	.148	.7029	.000
The City of Fairview	.121	.5746	.000
Spring City	.060	.2849	.000
Town of Holden	.048	.2280	.000
Kanosh	.041	.1947	.000
Town of Oak City	.041	.1947	.000
Total—21 Utah Municipal Purchasers	13.975%	66.3674%	.000%
COOPERATIVE PURCHASERS			
Moon Lake Electric Association, Inc.	2.018%	9.5835%	.000%
Mt. Wheeler Power, Inc.	1.803	8.5625	.000
Dixie-Escalante Rural Electric Association, Inc	1.548	7.3515	.000
Garkane Power Association, Inc	1.279	6.0740	.000
Bridger Valley Electric Association	.232	1.1018	.000
Flowell Electric Association	.202	.95	.000
Total—6 Cooperative Purchasers	7.082%	33.6326%	.000
			.000
Total—30 Renewal Power Purchasers	100.000%	100.000%	100.000%

(footnotes on following page)

(footnotes from previous page)

1 The Northern Transmission Cost and Entitlement Shares of each Renewal Power Purchaser having a point of delivery on the Northern Transmission System are determined by dividing such Renewal Power Purchaser's Generation Entitlement Share by the total of the Generation Entitlement Shares to be delivered on the Northern Transmission System.

2 The Southern Transmission Cost and Entitlement Shares of each Renewal Power Purchaser having a point of delivery on the Southern Transmission System are determined by dividing such Renewal Power Purchaser's Generation Entitlement Share by the total of the Generation Entitlement Shares to be delivered on the Southern Transmission System.

SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT

The following is a summary of certain provisions of the Excess Power Sales Agreement, as amended by the First Amendment to Excess Power Sales Agreement, which has been executed and delivered by each Utah Municipal and Cooperative Purchaser, as a seller (each referred to in this summary as a "Seller"), by Intermountain Consumer Power Association ("ICPA"), as agent for the Sellers (the "Agent"), by the Department and the cities of Burbank, Glendale and Pasadena, as purchasers (each referred to in this summary as an "Excess Purchaser"), and by the Department, serving as representative of the Excess Purchasers. Utah Associated Municipal Power Systems has succeeded to ICPA as Agent for the Sellers. This summary is not to be considered a full statement of the terms of the Excess Power Sales Agreement and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in this Appendix or in the document to which it is attached have the meanings set forth in the Excess Power Sales Agreement.

Nature of Obligation

Each Excess Purchaser is obligated to make the payments required under the Excess Power Sales Agreement solely from its electric revenue funds as a cost of purchased electric capacity and energy and an operating expense. Each Excess Purchaser has agreed to include in each of its annual power system budgets an appropriation from the revenues of its electric system sufficient to satisfy all payments required to be made during such fiscal year under the Excess Power Sales Agreement. The Excess Purchasers' obligations to pay the amounts required under the Excess Power Sales Agreement are not subject to reduction if the Project or any part thereof is not completed or is not operating or operable or if its output is suspended, interrupted, interfered with, reduced, curtailed or terminated in whole or in part. In addition, the Excess Purchasers are not relieved of their obligations to make payments under the Excess Power Sales Agreement in the event of any default by any Seller or the Agent.

Term

The term of the Excess Power Sales Agreement has commenced and will end when all payments required to be made under the Excess Power Sales Agreement and through the date of termination of the Power Sales Contracts have been made, unless terminated sooner as discussed under "Termination or Amendment" below.

Excess Entitlement Shares

The Excess Power Sales Agreement provides that during each Summer Season (March 25 to September 24) and each Winter Season (September 25 to March 24) of each Excess Power Supply Year (March 25 to March 24), each Seller will sell to each Excess Purchaser a specified portion of the entitlement to capacity and energy from the Project (the Seller's "Excess Entitlement Share"), not to exceed the Seller's Generation Entitlement Share. The execution of the Excess Power Sales Agreement by the Sellers and the sales of portions of their entitlement to capacity and energy from the Project by such Sellers do not reduce or modify the obligations of such Sellers under the Power Sales Contracts. The percentage of the entitlement to each generating unit of the Project being sold by a particular Seller to a particular Excess Purchaser is referred to as the "Contract Obligation" and computed by multiplying the Excess Entitlement Share of such Seller in effect at the time by the Purchase Percentage (divided by 100) of such Excess Purchaser, both as specified in the then current Appendix A to the Excess Power Sales Agreement (hereinafter referred to in this summary as "Appendix A"). Appendix A contains, for each Seller, Load Forecasts and Excess Entitlement Shares for each Season during a future ten-year period.

The Purchase Percentages of the Department, Burbank, Glendale and Pasadena are 86.281%, 3.781%, 2.382% and 7.556%, respectively. See "INTRODUCTION – The Power Purchasers" in the document to which this Appendix is attached for a discussion of the current status of sales by the Sellers of their respective Generation Entitlement Shares pursuant to the Excess Power Sales Agreement.

Each Seller's Excess Entitlement Share is equal to its Generation Entitlement Share for each Season for which such Seller has not recalled (*i.e.*, elected not to sell to the Excess Purchasers) any portion of its Generation Entitlement Share. To the extent, however, that any such Seller has recalled any portion of its Generation Entitlement Share, its Excess Entitlement Share is its full Generation Entitlement Share less the portion of its Generation Entitlement Share that has been recalled. For information regarding recalls of the Sellers' Generation Entitlement Shares that are currently scheduled, see "INTRODUCTION – The Power Purchasers" in the document to which this Appendix is attached.

During each Season from and after the time at which any generating unit produces power in excess of its allocated General Service Requirements ("net generation"), each Seller shall provide, and each Excess Purchaser shall acquire, the Contract Obligation applicable to such Seller and Excess Purchaser during such Season of the capacity and energy of the Project.

The Excess Power Sales Agreement provides for the delivery of capacity and energy to each Excess Purchaser at the Generation Station. Each Excess Purchaser has the obligation to arrange for transmission of its capacity and energy from such point to its system. Each Seller which has a right to use the Northern Transmission System has agreed in the Excess Power Sales Agreement to permit each Excess Purchaser to use a share of such Seller's entitlement to the capabilities of the Northern Transmission System proportionate to the share of that Seller's Generation Entitlement Share which is being sold to the Excess Purchaser under the Excess Power Sales Agreement.

In each Excess Power Supply Year, the Excess Power Sales Agreement permits revisions within limits to each Seller's specified Excess Entitlement Shares. These revisions will be included in a revised Appendix A which will be prepared by the Agent prior to the commencement of each Excess Power Supply Year. In its specification of its Excess Entitlement Share, a Seller may decrease its Excess Entitlement Share or leave it unchanged, without restriction, but may increase it for a particular season, in general, only upon agreement as to any increase by the Department and the Agent or, absent such agreement, in relation to a decrease in the Seller's Load Forecast for such season from its previously filed Load Forecast for such season.

No modification to an Excess Entitlement Share may be made for the first year covered by a new Appendix A from that Share specified for such year in the previously effective Appendix A. Notwithstanding the foregoing, a Seller may increase or decrease its Excess Entitlement Share for a Season upon notice given to the Agent not earlier than 120 nor later than 90 days prior to the beginning of the Season for which such increase or decrease is to take place, provided that the maximum increase or decrease which may be effective for any one Season under this provision with respect to all Sellers is 50 megawatts.

Required Payments

The Excess Power Sales Agreement obligates each Excess Purchaser to pay monthly for the account of a particular Seller an amount with respect to the minimum cost component of Monthly Power Costs associated with the Generation Station based on the Contract Obligation in effect for such month with respect to such Excess Purchaser and Seller. If the Seller has a right under its Power Sales Contract to use the Northern Transmission System, the Excess Purchaser is also obligated to pay a pro rata share of the minimum cost component associated with the Northern Transmission System in consideration for its entitlement to use of a portion of such system. Each Excess Purchaser is also obligated to pay an amount with respect to the variable cost component of Monthly Power Costs equal to the proportion which the

kilowatt hours delivered from the Project to such Excess Purchaser pursuant to the Excess Power Sales Agreement during the month preceding the billing of such amount bears to the total kilowatt hours delivered from the Project during such month. The amount of the variable cost component to be paid by each Excess Purchaser will be allocated to each Seller in proportion to the ratio which its Excess Entitlement Shares for the month to which such payment is applicable bears to the total Excess Entitlement Share for such month. The Excess Power Sales Agreement also obligates each Excess Purchaser to pay a proportionate share of the Agent's administrative expenses in performing its responsibilities under the Excess Power Sales Agreement. The Agent will bill each Excess Purchaser by the tenth day of each month for its share of the minimum cost component for such month, based on the amount in the then current Annual Budget, for its share of the variable cost component for the preceding month and for its administrative payment required for such current month. The Excess Purchaser is required to pay the amount billed no later than 15 days after receipt of such bill.

The Agent is required to pay amounts received for the account of a particular Seller to the Agency for such Seller's account promptly upon receipt thereof.

Excess Purchasers' Rate Covenant

Each Excess Purchaser has covenanted that it will establish, maintain, and collect rates and charges for the electric service of its system which will provide revenues sufficient, together with its available electric system reserves, to enable it to pay all amounts payable under the Excess Power Sales Agreement when due and to pay all other amounts payable from, and all liens on or lawful charges against, its electric system revenues.

Restrictions on Disposition

No Excess Purchaser may sell, lease or otherwise dispose of all or substantially all of its electric system except on 90 days' prior written notice to the Agent and upon satisfaction of the conditions that: (i) such Excess Purchaser assigns to the purchaser or lessee of its electric system all of its rights and interests under the Excess Power Sales Agreement, and such purchaser or lessee assumes all such obligations, (ii) the senior debt of such purchaser or lessee is rated in one of the two highest rating categories by at least one nationally-recognized bond rating agency, (iii) an independent engineer or nationally-recognized engineering firm selected by the Agent opines that such purchaser or lessee is reasonably able to charge and collect rates and charges for its electric service sufficient to meet its obligations under the Excess Power Sales Agreement and (iv) such Excess Purchaser has complied with the requirements of its Power Sales Contract with respect to such disposition. No Excess Purchaser may sell, assign or otherwise dispose of any portion of its entitlement under the Excess Power Sales Agreement except on 90 days' prior written notice to the Agent and except upon compliance with the applicable requirements of its Power Sales Contract.

Defaults and Remedies

In the event an Excess Purchaser fails to perform any of its obligations under the Excess Power Sales Agreement, the Agent may bring suit to enforce the covenants or obligations of such Excess Purchaser, seek to recover damages for a breach of the Excess Power Sales Agreement, or, in the event a payment due under the Excess Power Sales Agreement remains unpaid subsequent to the date it is due, upon 120 days' written notice to such Excess Purchaser, discontinue the delivery of capacity and energy to, and the use of all other Project facilities by, such Excess Purchaser under the Excess Power Sales Agreement during the period of such default. Except as a result of a transfer of a defaulting Excess Purchaser's rights described below, any such discontinuance will not reduce the obligation of any Excess Purchaser to make payments under the Excess Power Sales Agreement.

Upon a default by an Excess Purchaser and the discontinuance of the delivery of capacity and energy to, and use of other Project facilities by, such Excess Purchaser under the Excess Power Sales Agreement, the Agent will transfer the defaulting Excess Purchaser's rights under the Excess Power Sales Agreement to all requesting Excess Purchasers which are not in default, on a pro rata basis. Such requesting Excess Purchasers will assume the defaulting Excess Purchaser's obligations with respect to the rights so transferred. If any of the defaulting Excess Purchaser's rights with respect to the Project under the Excess Power Sales Agreement are not so transferred, the Agent will to the extent possible dispose of such rights on the best terms readily available that will not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Bonds (as such term is defined in the Excess Power Sales Agreement; the term "Bonds" as defined in the Excess Power Sales Agreement and as used in this summary means both Bonds (as defined in the Resolution) and Subordinated Indebtedness). The obligation of the defaulting Excess Purchaser to make payments under the Excess Power Sales Agreement shall be reduced to the extent that the Agent receives payment for such portion of the defaulting Excess Purchaser's rights which are so transferred or disposed of.

Termination or Amendment

In certain circumstances, the term of the Excess Power Sales Agreement may terminate prior to the date of termination of the Power Sales Contracts. Such termination of the Excess Power Sales Agreement (except with respect to certain rights to use the Northern Transmission System and the Southern Transmission System) would take place as soon after the earliest of the following occurs as all payments required under the Excess Power Sales Agreement by the Excess Purchasers through the date of such occurrence have been made:

(i) after a generating unit of the Project shall produce net generation, a condition shall exist that, for other than normal maintenance, no generating unit produces net generation (a "Complete Outage") and such Complete Outage continues to the last day of the second Excess Power Supply Year shown on the Appendix A in effect at the time such Complete Outage commences; or

(ii) the last day of the First Excess Power Supply Year for which the Appendix A then in effect shows the Total Excess Entitlement Share for the second Excess Power Supply Year to be zero.

Except as discussed above, the Excess Power Sales Agreement may not be terminated or amended materially as to any one or more of the Excess Purchasers except upon written consent or waiver by each other Excess Purchaser and upon similar amendment being made to the Excess Power Sales Agreement with respect to each other Excess Purchaser which so requests, nor may it be terminated or amended materially as to any one or more of the Sellers except upon written consent or waiver by each other Seller and upon similar amendment being made to the Excess Power Sales Agreement with respect to each other Seller which so requests.

SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR SALE OF RENEWAL EXCESS POWER

The following is a summary of certain provisions of the Agreement for Sale of Renewal Excess Power, which has been executed and delivered by each Utah Municipal and Cooperative Purchaser, as a seller (each referred to in this summary as a "Seller"), by the Agency, as agent for the Sellers (the "Agent"), by the Department, as the sole purchaser (referred to in this summary as the "Excess Purchaser"), and by the Department, serving as representative of the Excess Purchaser. This summary is not to be considered a full statement of the terms of the Agreement for Sale of Renewal Excess Power and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in this Appendix or in the document to which it is attached have the meanings set forth in the Agreement for Sale of Renewal Excess Power.

Nature of Obligation

The Excess Purchaser is obligated to make the payments required under the Agreement for Sale of Renewal Excess Power solely from its electric revenue funds as a cost of purchased electric capacity and energy and an operating expense. The Excess Purchaser has agreed to include in each of its annual power system budgets an appropriation from the revenues of its electric system sufficient to satisfy all payments required to be made during such fiscal year under the Agreement for Sale of Renewal Excess Power. The Excess Purchaser's obligations to pay the amounts required under the Agreement for Sale of Renewal Excess Power are not subject to reduction if the Project or any part thereof is not completed or is not operating or operable or if its output is suspended, interrupted, interfered with, reduced, curtailed or terminated in whole or in part. In addition, the Excess Purchaser is not relieved of its obligation to make payments under the Agreement for Sale of Renewal Excess Power in the event of any default by any Seller or the Agent.

Term

The term of the Agreement for Sale of Renewal Excess Power has commenced and will end when all payments required to be made under the Agreement for Sale of Renewal Excess Power and through the date of termination of the Renewal Power Sales Contracts have been made, unless terminated sooner as discussed under "Termination or Amendment" below. Although the Agreement for Sale of Renewal Excess Power has become effective, it will govern the purchase and sale of each Seller's Excess Entitlement Share only from and after June 16, 2027.

Excess Entitlement Shares

The Agreement for Sale of Renewal Excess Power provides that during each Summer Season (12:01 a.m. on June 1 to 12:01 a.m. on October 1) and each Winter Season (12:01 a.m. on October 1 to 12:01 a.m. on June 1) of each Excess Power Supply Year (12:01 a.m. on July 1 to 12:01 a.m. on July 1), each Seller will sell to the Excess Purchaser a specified portion of the entitlement to capacity and energy from the Project (the Seller's "Excess Entitlement Share"), not to exceed the Seller's Generation Entitlement Share. The execution of the Agreement for Sale of Renewal Excess Power by the Sellers and the sales of portions of their entitlement to capacity and energy from the Project by such Sellers do not reduce or modify the obligations of such Sellers under the Renewal Power Sales Contracts. The percentage of the entitlement to each generating unit of the Project being sold by a particular Seller to the Excess Purchaser is referred to as the "Excess Power Obligation" and computed by multiplying the Excess Entitlement Share of such Seller in effect at the time by the Purchase Percentage (expressed as a decimal) of the Excess Purchaser, both as specified in the then current Appendix A to the Agreement for Sale of Renewal Excess Power (hereinafter referred to in this summary as "Appendix A"). Appendix A contains, for each Seller, such Seller's election for the Excess Entitlement Share for each Season, subject to

modification as provided in the Agreement for Sale of Renewal Excess Power. The Purchase Percentage of the Department is 100%.

Each Seller's Excess Entitlement Share is equal to its Generation Entitlement Share for each Season for which such Seller has not recalled (*i.e.*, elected not to sell to the Excess Purchaser) any portion of its Generation Entitlement Share. To the extent, however, that any such Seller has recalled any portion of its Generation Entitlement Share, its Excess Entitlement Share is its full Generation Entitlement Share less the portion of its Generation Entitlement Share that has been recalled. The Sellers must make their election with respect to their Excess Entitlement Shares at least 12 months prior to June 16, 2027 (referred to as the Operational Period Commencement Date in the Agreement for Sale of Renewal Excess Power).

During each Season from and after the Operational Period Commencement Date, each Seller shall provide, and the Excess Purchaser shall acquire, the Excess Power Obligation applicable to such Seller and the Excess Purchaser during such Season of the capacity and energy of the Project.

The Agreement for Sale of Renewal Excess Power provides for the delivery of capacity and energy to the Excess Purchaser at the Generation Station. The Excess Purchaser has the obligation to arrange for transmission of its capacity and energy from such point to its system. Each Seller which has a right to use the Northern Transmission System has agreed in the Agreement for Sale of Renewal Excess Power to permit the Excess Purchaser to use a share of such Seller's entitlement to the capabilities of the Northern Transmission System proportionate to the share of that Seller's Generation Entitlement Share which is being sold to the Excess Purchaser under the Agreement for Sale of Renewal Excess Power, except that each Seller has agreed to an assignment of a fixed amount of Northern Transmission System entitlement to the Excess Purchaser equal to fifty percent of such Seller's Excess Northern Transmission System Entitlement (which is the Seller's Northern Transmission System Entitlement in excess of the capacity on the Northern Transmission System required for delivery of such Seller's Generation Entitlement Share).

In each Excess Power Supply Year, the Agreement for Sale of Renewal Excess Power permits revisions within limits to each Seller's specified Excess Entitlement Shares. These revisions will be included in a revised Appendix A which will be prepared by the Agent prior to the commencement of each season to reflect any elections made with respect to such season. In its specification of its Excess Entitlement Share, a Seller may leave its Excess Entitlement Share unchanged, decrease its Excess Entitlement Share by up to fifty percent of its Retained Generation Entitlement Share that will be in effect in the season with respect to which such election is being made, or may increase it without restriction for a particular season but with the requirement that such increase must remain in effect for three years. A Seller must make any election to increase or decrease its Excess Entitlement Share with respect to a particular season at least 12 months prior to the commencement of that season.

Required Payments

The Agreement for Sale of Renewal Excess Power obligates the Excess Purchaser to pay monthly for the account of a particular Seller an amount with respect to the minimum cost component of Monthly Power Costs associated with the Generation Station based on the Contract Obligation in effect for such month with respect to the Excess Purchaser and such Seller. If the Seller has a right under its Renewal Power Sales Contract to use the Northern Transmission System, the Excess Purchaser is also obligated to pay a pro rata share of the minimum cost component associated with the Northern Transmission System in consideration for its entitlement to use of a portion of such system. The Excess Purchaser is also obligated to pay an amount with respect to the variable cost component of Monthly Power Costs equal to the proportion which the kilowatt hours delivered from the Project to the Excess Purchaser pursuant to the Agreement for Sale of Renewal Excess Power during the month preceding the billing of such amount bears to the total kilowatt hours delivered from the Project during such month. The amount of the variable cost component to be paid by the Excess Purchaser will be allocated to each Seller in proportion to the ratio

which its Excess Entitlement Shares for the month to which such payment is applicable bears to the total Excess Entitlement Share for such month. The Agreement for Sale of Renewal Excess Power also obligates the Excess Purchaser to pay a proportionate share of the Agent's administrative expenses in performing its responsibilities under the Agreement for Sale of Renewal Excess Power. The Agent will bill the Excess Purchaser by the fifth day of each month for its share of the minimum cost component for such month, based on the amount in the then current Annual Budget, for its share of the variable cost component for the preceding month and for its administrative payment required for such current month. The Excess Purchaser is required to pay the amount billed no later than 20 days after receipt of such bill.

The Agent is required to pay amounts received for the account of a particular Seller to the Agency for such Seller's account promptly upon receipt thereof.

Excess Purchaser's Rate Covenant

The Excess Purchaser has covenanted that it will establish, maintain, and collect rates and charges for the electric service of its system which will provide revenues sufficient, together with its available electric system reserves, to enable it to pay all amounts payable under the Agreement for Sale of Renewal Excess Power when due and to pay all other amounts payable from, and all liens on or lawful charges against, its electric system revenues.

Restrictions on Disposition

The Excess Purchaser may not sell, lease or otherwise dispose of all or substantially all of its electric system except on 90 days' prior written notice to the Agent and upon satisfaction of the conditions that: (i) the Excess Purchaser assigns to the purchaser or lessee of its electric system all of its rights and interests under the Agreement for Sale of Renewal Excess Power, and such purchaser or lessee assumes all such obligations, (ii) the senior debt of such purchaser or lessee is rated in one of the two highest rating categories by at least one nationally-recognized bond rating agency, (iii) an independent engineer or nationally-recognized engineering firm selected by the Agent opines that such purchaser or lessee is reasonably able to charge and collect rates and charges for its electric service sufficient to meet its obligations under the Agreement for Sale of Renewal Excess Power and (iv) the Excess Purchaser has complied with the requirements of its Renewal Power Sales Contract with respect to such disposition. The Excess Purchaser may not sell, assign or otherwise dispose of any portion of its Excess Power Obligation or associated Northern Transmission System or Switchyard entitlements except on prior written notice to the Agent and except upon compliance with the applicable requirements of the Agreement for Sale of Renewal Excess Power.

Defaults and Remedies

In the event the Excess Purchaser fails to perform any of its obligations under the Agreement for Sale of Renewal Excess Power, the Agent may bring suit to enforce the covenants or obligations of the Excess Purchaser, seek to recover damages for a breach of the Agreement for Sale of Renewal Excess Power, or, in the event a payment due under the Agreement for Sale of Renewal Excess Power remains unpaid subsequent to the date it is due, upon 120 days' written notice to the Excess Purchaser, discontinue the delivery of capacity and energy to, and the use of all other Project facilities by, the Excess Purchaser under the Agreement for Sale of Renewal Excess Power during the period of such default. Except as a result of a transfer, upon a default by the Excess Purchaser, of the Excess Purchaser's rights described below, any such discontinuance will not reduce the obligation of the Excess Purchaser to make payments under the Agreement for Sale of Renewal Excess Power.

Upon a default by the Excess Purchaser and the discontinuance of the delivery of capacity and energy to, and use of other Project facilities by, the Excess Purchaser under the Agreement for Sale of

Renewal Excess Power, the Agent will to the extent possible dispose of such rights on the best terms readily available that will not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Project Indebtedness (as such term is defined in the Renewal Power Sales Contracts) of the Agency (which term as defined in the Renewal Power Sales Contracts and as used in this summary means both Bonds (as defined in the Resolution) and Subordinated Indebtedness). Upon such a transfer or disposition, the obligation of the Excess Purchaser to make payments under the Agreement for Sale of Renewal Excess Power shall be reduced to the extent that the Agent receives payment for such portion of the Excess Purchaser's rights which are so transferred or disposed of.

Termination or Amendment

In certain circumstances, the term of the Agreement for Sale of Renewal Excess Power may terminate prior to the date of termination of the Renewal Power Sales Contracts. Such termination of the Agreement for Sale of Renewal Excess Power (except with respect to certain rights to use the Northern Transmission System and the Southern Transmission System) would take place as soon after the earliest of the following occurs as all payments required under the Agreement for Sale of Renewal Excess Power by the Excess Purchaser through the date of such occurrence have been made:

(i) a condition shall exist that, for other than normal maintenance, no generating facilitating at the Project produces power at the high side of its generating transformers in excess of its allocated General Service Requirements (a "Complete Outage") and such Complete Outage continues for a period of 18 months; or

(ii) The last day of the end of the six-month period next following the Excess Power Supply Year for which Appendix A sets forth the Total Excess Entitlement Share as zero with respect to both the Summer Season and the Winter Season.

Except as discussed above, the Agreement for Sale of Renewal Excess Power may not be terminated or amended materially as to the Excess Purchaser except upon written agreement by the Excess Purchaser, nor may it be terminated or amended materially as to any one or more of the Sellers except upon written consent or waiver by each other Seller and upon similar amendment being made to the Agreement for Sale of Renewal Excess Power with respect to each other Seller which so requests.

SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT

The following is a summary of certain provisions of the Construction Management and Operating Agreement ("CMOA") entered into between the Agency and the Department. This summary is not to be considered a full statement of the terms of the CMOA and accordingly is qualified by reference thereto and subject to the full text thereof. Capitalized terms not defined in this Appendix or in the document to which it is attached have the meanings set forth in the CMOA.

The CMOA provides for the appointment by the Agency of the Department as Project Manager and Operating Agent for planning, negotiating, designing, constructing, insuring, contracting for, administering, operating and maintaining the Project. The Department will act as the Agency's agent in fulfilling its duties as Project Manager and Operating Agent, subject to the provisions of the Resolution and the Power Sales Contracts and to the supervision and, as to certain matters, approval, of the Coordinating Committee established under the Power Sales Contracts. The CMOA has become effective and will remain in effect, unless modified, until the expiration of the Power Sales Contracts. The Agency has covenanted in the Resolution that it will not consent or agree to any amendment of the CMOA, other than the extension thereof, which will in any manner materially impair or adversely affect the rights of the Agency thereunder or the rights or security of the Bondholders under the Resolution (see "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Covenants with Respect to Power Sales Contracts and Construction Management and Operating Agreement" in Appendix A to the document to which this Appendix is attached).

Responsibility of Project Manager and Operating Agent

As Project Manager and Operating Agent, the Department is responsible for performing and completing the Construction Work and performing the Operating Work for the Project, including, but not limited to, the following:

1. Preparing recommendations concerning the initial descriptions of the design of the Project and the scope of Construction Work thereon, an initial budget for the Cost of Acquisition and Construction and the proposed Date of Firm Operation for each generating unit, and annual operating budgets for the Project and any revisions thereto;

2. Recommending to the Coordinating Committee for its review, modification and approval (a) the policies, criteria and procedures regarding operation, maintenance, scheduling of capacity and energy and (b) proposed Capital Improvements;

3. Negotiating, administering, performing and enforcing on behalf of the Agency the Power Sales Contracts, the Resolution, the Operating Agreements, all Agreements concerning construction of the Project or the acquisition of fuel or water therefor, any other agreements to which the Agency is a party relating to the ownership, feasibility, design, construction or operation of the Project and any additional agreements designed by the Agency and the Coordinating Committee;

4. Arranging for engineering, consultants and legal counsel, the placement of insurance, and the acquisition of machinery, tools, land or rights in land, water or water rights, leases, licenses, easements, power and supplies necessary for the performance of the Construction Work and Operating Work;

5. Constructing and operating the Project in accordance with the Project Agreements, Prudent Utility Practice and, as to construction, the descriptions of the Project set forth in the Power Sales

Contracts, and submitting requisitions for payment of costs thereof in accordance with the terms of the CMOA; and

6. Maintaining financial records, accounting for all payments made, including taxes and payments in lieu of taxes and providing, on an annual basis, a statement of actual aggregate Monthly Power Costs and Contract Monthly Power Costs for the prior year.

Coordinating Committee

The CMOA and the Power Sales Contracts provide that certain actions to be taken by the Project Manager or Operating Agent are subject to the review, modification and approval of the Coordinating Committee. If the Coordinating Committee is unable to, or fails to, agree with respect to any matter or dispute which it is authorized to determine, resolve, approve or otherwise act upon after a reasonable opportunity to do so, or within the time limits specified in the CMOA, the Project Manager or Operating Agent, upon written notice to the Agency and each member of the Coordinating Committee, may, pending action by the Coordinating Committee, take such action, consistent with Prudent Utility Practice, as it determines is necessary for the timely performance of its obligations under the CMOA.

Payment of Costs of Construction Work and Operating Work

All costs of construction and operation of the Project, including the costs of Capital Improvements, will be paid only from the funds held under the Resolution, upon compliance with the requirements thereof regarding withdrawal and expenditure of such funds. Subject thereto, the Agency has agreed to provide for payment of such costs so that the Department, in its capacity as Project Manager or Operating Agent, will not have to expend any of its own funds on behalf of the Agency. The Agency is not obligated to pay any item or cost of construction or operation other than from funds available therefor under the Resolution or the Power Sales Contracts.

The CMOA requires that the Project Manager or Operating Agent, in seeking payment for any items of cost of Construction Work or Operating Work, submit a certified requisition to the Agency, which the Agency shall either pay from the revolving fund established under the Resolution or file with the Trustee for payment. The Department will submit requisitions monthly covering its estimated Project Manager's Costs for Construction Work for the following month and, commencing at least five days prior to the Date of Firm Operation of each generating unit, covering its estimated Operating Agent's Costs for Operating Work for the following month. The Agency has agreed to cause such requisitions to be paid by the fifteenth day of the month to which such estimates apply.

Scheduling of Capacity and Entitlement

The Operating Agent shall schedule capacity and energy from the Generation Station and transmission system entitlement in accordance with the provisions of the CMOA and the practices and procedures developed by the Operating Agent and approved by the Coordinating Committee.

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APPENDIX C

INTERMOUNTAIN POWER AGENCY

Consolidated Financial Statements for the Years Ended June 30, 2021 and 2020 and Independent Auditors' Report

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Intermountain Power Agency

Financial Statements as of and for the Years Ended June 30, 2021 and 2020, Supplemental Schedule for the Years Ended June 30, 2021 and 2020, and Independent Auditors' Report

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Intermountain Power Agency:

Report on the Financial Statements

We have audited the accompanying financial statements of Intermountain Power Agency (IPA), which comprise the statements of net position as of June 30, 2021 and 2020, and the related statements of revenues and expenses and changes in net position and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

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

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

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of IPA as of June 30, 2021 and 2020, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis on pages 3 – 7 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audits of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the basic financial statements as a whole. The accompanying Supplemental Schedule of Changes in Funds Established by the IPA Revenue Bond Resolution for the Years Ended June 30, 2020 and 2021 is presented for the purpose of additional analysis and is not a required part of the basic financial statements. The supplemental schedule is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the basic financial statements or to the basic financial statements themselves, and other additional procedures in accordance with auditing standards generally accepted in the United States of America. In our opinion, the supplemental schedule is fairly stated, in all material respects, in relation to the basic financial statements as a whole.

Deloitte & Touche LLP

September 28, 2021

Intermountain Power Agency

Management's Discussion and Analysis

The Intermountain Power Agency (IPA) is a political subdivision of the State of Utah formed by 23 Utah municipalities pursuant to the provisions of the Utah Interlocal Co-operation Act. IPA owns, finances, operates, and maintains a two-unit, coal-fired, steam-electric generating plant and switchyard located in Millard County, Utah and transmission systems through portions of Utah, Nevada and California (the "Project"). IPA has irrevocably sold the entire capacity of the Project pursuant to Power Sales Contracts, as amended (the "Contracts"), to 35 utilities (the "Purchasers"). The Purchasers are unconditionally obligated to pay all costs of operation, maintenance and debt service, whether or not the Project or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, reduced, or terminated.

IPA's financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and consist of statements of net position, statements of revenues and expenses and changes in net position, statements of cash flows, and the related notes to the financial statements. The statements of net position report IPA's assets, deferred outflows of resources, liabilities, and deferred inflows of resources as of the end of the fiscal year. Investments are stated at fair value. No net position is reported in the statements of net position because IPA is completely debt financed and the Contracts contain no provision for profit. The Contracts govern how and when Project costs become billable to the Purchasers. Net costs billed to participants not yet expensed in accordance with U.S. GAAP or expenses recognized but not currently billable under the Contracts are recorded as net costs billed to participants not yet expensed (a deferred inflow) or deferred as net costs to be recovered from future billings to participants (an asset), respectively, in IPA's statements of net position. In future periods, the deferred inflow will be settled, or the asset will be recovered as the associated expenses are recognized in accordance with U.S. GAAP or when they become billable Project costs in future participant billings, respectively. At June 30, 2021 and 2020, total accumulated Project costs billed to participants exceeded accumulated U.S. GAAP expenses, resulting in a deferred inflow, net costs billed to participants not yet expensed. Over the life of the Project, aggregate U.S. GAAP expenses will equal aggregate billed Project costs. The statements of revenues and expenses and changes in net position report the results of operations and changes in net position, and the statements of cash flows report the resulting cash flows for the fiscal year. Net costs billed to participants not yet expensed, as reported in the statements of revenues and expenses and changes in net position, reflects the extent to which billable Project costs are greater than U.S. GAAP expenses during the fiscal year. The following table summarizes the financial condition and operations of IPA for the years ended June 30, 2021, 2020 and 2019 (in thousands):

	2021	2020	2019
Assets			
Utility plant, net	$ 692,149	$ 719,252	$ 794,242
Cash, cash equivalents, and investments	258,283	226,076	222,015
Other	112,933	91,470	61,589
Total assets	1,063,365	1,036,798	1,077,846
Deferred outflows of resources	135,854	159,715	66,116
Total assets and deferred outflows of resources	$ 1,199,219	$ 1,196,513	$ 1,143,962
Liabilities			
Debt	$ 280,499	$ 446,152	$ 611,799
Commercial paper notes	-	35,200	66,900
Other	395,983	417,064	249,221
Total liabilities	676,482	898,416	927,920
Net costs billed to participants not yet expensed	519,056	296,402	214,839
Other	3,681	1,695	1,203
Total deferred inflows of resources	522,737	298,097	216,042
Total liabilities and deferred inflows of resources	$ 1,199,219	$ 1,196,513	$ 1,143,962
Revenues and Expenses and Changes in Net Position			
Operating revenues, net	$ 558,461	$ 555,007	$ 606,884
Fuel	(175,409)	(158,934)	(193,000)
Other operating expenses	(159,028)	(294,639)	(329,579)
Operating income	224,024	101,434	84,305
Non-operating income	1,133	1,113	2,323
Net interest charges	(2,503)	(20,984)	(42,014)
Net costs billed to participants not yet expensed	(222,654)	(81,563)	(44,614)
Change in net position	$ -	$ -	$ -

Financial Highlights:

Assets

The net increase in gross utility plant of $56 million in 2021 resulted from additions of $68 million offset by retirements of $12 million. The 2021 additions were principally for the initial construction and engineering for the gas turbine associated with IPA repowering (see discussion of Project Repowering below), the procurement and installation of an additional spare transformer for the Adelanto Converter Station, the refurbishment of microwave equipment, and the rehabilitation of the process water pond in compliance with environmental requirements. The net increase in gross utility plant of $34 million in 2020 resulted from additions of $35 million offset by retirements of $1 million. The 2020 additions were principally for the initial construction and engineering for the gas turbine associated with IPA repowering, the procurement and installation of an additional spare transformer for the Adelanto Converter Station and the ongoing installation of groundwater remediation wells in compliance with environmental requirements.

The 2021 increase in cash, cash equivalents and investments, combined current and restricted of $32 million is primarily due to an increase of $21 million in the July 1 principal and interest payments on debt compared to the prior year, an increase in the credit to participants of $15 million compared to the prior year that will be credited against purchaser billings in October, offset by a decrease of $4 million in other reserves used for repowering costs. The 2020 increase in cash, cash equivalents and investments, combined current and restricted of $4 million, while not significant, is due to the receipt of insurance proceeds from

the 2017 transformer failure at the Adelanto Converter Station. These proceeds were included in the credit to participants at year end.

The 2021 increase of $22 million in other assets was primarily caused by an increase of $6 million in receivables from participants as higher variable energy was scheduled in June 2021 compared to the prior year and a $30 million increase in prepaid personnel service contract costs due to IPA's contractual rights and obligations under a Personnel Services Contract for certain employee pensions and other postretirement benefits resulting in a reported asset in the current year compared to a liability in the prior year. These increases were offset by a $16 million decrease in fuel inventory as a higher percentage of existing reserves were used compared to coal purchases to bring the fuel reserve to its optimal level. The 2020 increase of $30 million in other assets was primarily caused by a $28 million increase of coal inventory due to lower power scheduling compared to that forecasted. The budget was based on a planned capacity of 65% and coal purchases were contracted accordingly, however, actual scheduled capacity was only 43%, resulting in an increase in coal inventory.

Deferred Outflows of Resources

Deferred outflows of resources primarily consist of unamortized refunding charge on defeasance of debt and unamortized asset retirement costs. The decrease of $24 million in 2021 was due to $38 million in normal amortization offset by $14 million of additional unamortized retirements costs (see Note 10). The increase of $94 million in 2020 was due to an additional $135 million in unamortized retirement costs (see Note 10) offset by $41 million of normal amortization.

Liabilities

During 2021, $19 million of Transition Project Indebtedness was issued in the form of 2019 Drawdown Bonds (see Note 8) to finance initial construction for the Project Repowering (see discussion of Project Repowering below). This was offset by $185 million of scheduled principal maturities on bonds and subordinated notes that were paid. Commercial paper notes decreased by $35 million as the remaining outstanding notes were paid. Other liabilities decreased by $21 million in 2021. As discussed above, IPA's contractual rights and obligations for certain employee pensions and postretirement benefits resulted in a reported asset in the current year compared to a liability in the prior year, resulting in a decrease in personnel services contract obligations of $64 million along with a $2 million decrease in other non-current liabilities. This was offset by a $14 million increase in asset retirement obligations due to inflation adjustments, a $15 million increase in credit to participants and a $16 million increase in accounts payable compared to the prior year.

During 2020, $23 million of Transition Project Indebtedness was issued in the form of 2019 Drawdown Bonds (see Note 8) to finance initial construction for the Project Repowering (see discussion of Project Repowering below). This was offset by $189 million of scheduled principal maturities on bonds and subordinated notes that were paid. Commercial paper notes decreased by $32 million through scheduled sinking fund payments. Other liabilities increased by $168 million in 2020. The increase was primarily attributable to $135 million of additional asset retirement obligations as contemplated in the Retirement Plan (see Note 10), a $31 million increase in credit to participants, a $16 million increase in personnel service contract and other obligations related to pension and other postretirement benefit obligations, offset by a $12 million decrease in accounts payable and a $2 million decrease in interest payable compared to the prior year.

Standard & Poor's rates IPA's subordinate lien bonds A+. Fitch rates the subordinate lien bonds AA-. Moody's rates IPA's subordinate lien bonds A1. The subordinated notes and drawdown bonds are not rated because they are not publicly traded. All ratings are unchanged from the prior year. In the prior year the commercial paper was rated at A1 by Standard & Poor's and F1 by Fitch.

Deferred Inflows of Resources
At June 30, 2021 and 2020, total accumulated Project costs billed to participants exceeded accumulated U.S. GAAP expenses. Accordingly, the excess of such billings is reported as a deferred inflow, net costs billed to participants not yet expensed at June 30, 2021 and 2020. The resulting changes in net costs billed to participants not yet expensed are outlined in Note 4.

Revenues and Expenses and Changes in Net Position
Net operating revenues increased $4 million in 2021 and decreased by $52 million in 2020. The 2021 change is not significant. In 2020, the decrease is primarily due to less revenue that was billed to the Purchasers associated with a decrease in scheduled power as reflected by decreased plant capacity. In addition, changes in revenues from corresponding changes to net costs billed to participants not yet expensed in 2021 and 2020 are due principally to the following: a decrease of $1 million and an increase of $35 million in 2021 and 2020, respectively, for bond, subordinated note and commercial paper notes principal requirements; a decrease of $122 million and $36 million in 2021 and 2020, respectively, in billings for previously deferred expenses in conformity with U.S. GAAP, and an increase of $20 million in 2021 and a decrease of $34 million in 2020 for capital improvements and required fund deposits.

Fuel expense increased by $16 million in 2021 and decreased by $34 million in 2020. The increase in 2021 is primarily due to an 8% increase in net capacity during the year. Conversely, the decrease in 2020 is primarily related to a 22% decrease in net capacity during that year. Other operating expenses decreased by $135 million in 2021 due primarily to a benefit of approximately $86 million in 2021 compared to an expense of $45 million in 2020 arising from changes in the reported asset and liability amounts under a Personnel Services Contract for IPSC's employee pensions and other postretirement benefits. Other operating expenses decreased by $35 million in 2020 due primarily to a $11 million decrease in maintenance expense from the postponement of the planned spring outage due to COVID-19 concerns offset by an $8 million increase in depreciation and amortization expense due primarily to the amortization of additional asset retirement obligations as contemplated in the Retirement Plan. The remaining decrease in operating expense is due to the 22% decrease in net capacity during the year.

Net interest charges decreased by $18 million and $21 million in 2021 and 2020, respectively, due to the decrease in outstanding debt, combined with the impact of the required adjustment to the interest rates on certain outstanding subordinated notes. The Subordinated Notes require an annual adjustment of interest rates to reflect the impact of cash flow savings from IPA retirements of bonds that had previously been defeased through subordinated notes. These adjustments resulted in certain notes having negative interest (see Note 6). Other non-operating income did not change significantly in 2021 and decreased by $1 million in 2020 primarily due to fluctuations in fly ash sales. Changes in net position are zero because IPA is completely debt financed and the Contracts contain no provision for profit.

Electric Industry Legislation and Regulation
California has enacted legislation prohibiting its municipally owned electric utilities from entering into new long-term financial commitments for base load generation that do not meet certain greenhouse gases emissions performance standards. During August 2018, the California legislature passed legislation stating California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. These and other environmental regulation issues are discussed in Note 13 to the financial statements.

Project Repowering
Over the past several years, IPA and the Purchasers have engaged in strategic activities so that the Project may continue operation in compliance with current electric industry regulation applicable to its Purchasers, beyond the expiration of the current Power Sales Contracts. IPA and the Purchasers executed the Second Amendatory Power Sales Contracts, which provides that the Project be repowered and that IPA offer the Purchasers renewal in their generation and associated transmission entitlements through Renewal Power

Sales Contracts (the "Renewal Contracts"), the term of which commences upon the termination of the current Power Sales Contracts on June 15, 2027. IPA and 32 of the Purchasers entered into Renewal Contracts, which became effective on January 16, 2017. Two renewing California Purchasers subsequently provided a notice of termination of their Renewal Contracts to IPA effective November 1, 2019. All entitlement shares abandoned by non-renewing purchasers are fully allocated among the remaining purchasers. The 50-year term of the Renewal Contracts is to commence upon the termination of the Contracts.

On September 24, 2018, IPA and the Purchasers approved changes to the repowering that constituted an Alternative Repowering under the Contracts. The Alternative Repowering is described to include the construction and installation of two combined-cycle natural gas fired power blocks, each block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW.

On August 6, 2019, the IPA Board and Intermountain Power Project (IPP) Coordinating Committee formally approved the Retirement Plan for the decommissioning and retirement of the existing facilities that are not to be used for the generation or transmission of power pursuant to the Contracts or the Renewal Contracts, which created a contractual requirement to retire certain capital assets under the Renewal Contracts. This resulted in an additional $96.4 million for the retirement and dismantling of existing generating station assets and $37.2 million for the retirement and dismantling of existing converter station assets which were recorded as asset retirement obligations during the year ended June 30, 2020.

On November 25, 2019, IPA and the Purchasers approved a Plan of Finance for funding renewal project activities that anticipates using shorter-term bridge financing in early project stages followed by long-term financing as required to fund anticipated costs to complete construction. Accordingly, on December 30, 2019, IPA entered into a bond purchase agreement with Royal Bank of Canada (RBC), by which IPA issued one subseries of Tax-Exempt Drawdown Bonds and one subseries of Taxable Drawdown Bonds, collectively called the 2019 Drawdown Series. Up to $100 million of drawdown bonds can be issued. As of June 30, 2021 and 2020, $41.5 million $22.5 million, respectively, of drawdown bonds have been issued.

On February 14, 2020, IPA awarded Mitsubishi Hitachi Power Systems a contract for two M501JAC power trains for the renewal project gas turbines. Initial milestone payments for turbine construction commenced in April 2020. The turbines will be commercially guaranteed capable of using a mix of 30% hydrogen and 70% natural gas at start-up in 2025. This mixture will reduce carbon emissions by more than 75% compared to the retiring coal-fueled technology.

COVID-19

In March 2020, COVID-19 was officially declared a pandemic and has been having significant effects in most markets and economies. Throughout the pandemic, the Project has continued to operate, and IPA has not experienced any significant impact to its financial position and results of operations to date. However, the future impact of COVID-19 on IPA's financial position and results of operations will depend on may factors, including: (i) the duration and spread of the outbreak, (ii) the restrictions and recommendations of health organizations and governments, (iii) the effects on the financial markets, and (iv) the effects in general on the economy. It is not possible to reasonably estimate the length and severity of these developments and the impact of COVID-19 on the financial conditions and results of operations of IPA in future periods.

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INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
JUNE 30, 2021 AND 2020 (IN THOUSANDS)

ASSETS	2021	2020
UTILITY PLANT:		
Electric plant in service	$ 3,180,813	$ 3,124,696
Less accumulated depreciation	(2,488,664)	(2,405,444)
Net	692,149	719,252
RESTRICTED ASSETS:		
Cash and cash equivalents	55,699	4,934
Investments	11,330	42,090
Interest receivable	16	-
Total	67,045	47,024
OTHER NON-CURRENT ASSETS		
Prepaid personnel services contract costs	30,007	-
Other	2,579	2,022
Total	32,586	2,022
Total non-current assets	791,780	768,298
CURRENT ASSETS:		
Cash and cash equivalents	29,829	67,639
Investments	161,425	111,413
Interest receivable	122	294
Receivable from participants	7,752	1,161
Fuel inventories	43,498	59,845
Materials and supplies	22,271	21,831
Other	6,688	6,317
Total current assets	271,585	268,500
Total assets	1,063,365	1,036,798
DEFERRED OUTFLOWS OF RESOURCES:		
Unamortized refunding charge	7,860	18,788
Unamortized asset retirement costs	126,316	139,059
Other	1,678	1,868
Total deferred outflows of resources	135,854	159,715
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	$ 1,199,219	$ 1,196,513

See notes to financial statements.

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
JUNE 30, 2021 AND 2020 (IN THOUSANDS)

LIABILITIES	2021	2020
LONG-TERM PORTION OF BONDS PAYABLE - Net	$ 40,062	$ 86,579
LONG-TERM PORTION OF SUBORDINATED NOTES PAYABLE - Net	79,936	152,170
LONG-TERM DRAWDOWN BONDS	41,500	22,500
ADVANCES FROM SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY	10,930	10,930
OTHER NON-CURRENT LIABILITIES:		
Personnel services contract obligations	-	64,242
Asset retirement obligations	273,242	259,243
Other	1,854	3,796
Total	275,096	327,281
CURRENT LIABILITIES:		
Commercial paper notes	-	35,200
Current maturities of bonds payable	44,030	22,400
Current maturities of subordinated notes payable	74,971	162,503
Interest payable	2,565	2,838
Accrued credit to participants	50,949	36,136
Accounts payable and accrued liabilities	56,443	39,879
Total current liabilities	228,958	298,956
COMMITMENTS AND CONTINGENT LIABILITIES (Notes 1, 7, 11, and 13)	-	-
Total liabilities	676,482	898,416
DEFERRED INFLOWS OF RESOURCES:		
Net costs billed to participants not yet expensed	519,056	296,402
Other	3,681	1,695
Total deferred inflows of resources	522,737	298,097
TOTAL LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	$ 1,199,219	$ 1,196,513

See notes to financial statements.

(Concluded)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF REVENUES AND EXPENSES AND CHANGES IN NET POSITION FOR THE YEARS ENDED JUNE 30, 2021 AND 2020 (IN THOUSANDS)

	2021	2020
OPERATING REVENUES:		
Power sales to participants	$ 609,552	$ 591,285
Less credit to participants	(51,091)	(36,278)
Net revenues	558,461	555,007
OPERATING EXPENSES (INCOME):		
Fuel	175,409	158,934
Operation	(46,750)	88,198
Maintenance	66,096	52,013
Depreciation and amortization	122,095	136,032
Taxes and payment in lieu of taxes	17,587	18,396
Total expenses	334,437	453,573
OPERATING INCOME	224,024	101,434
NON-OPERATING INCOME	1,133	1,113
INTEREST CHARGES:		
Interest on bonds, subordinated notes, and other debt	(8,177)	6,691
Financing expenses (principally amortization of bond discount and refunding charge on defeasance of debt)	11,928	18,316
Earnings on investments	(1,248)	(4,023)
Net interest charges	2,503	20,984
NET COSTS BILLED TO PARTICIPANTS NOT YET EXPENSED	222,654	81,563
CHANGE IN NET POSITION	$ -	$ -

See notes to financial statements.

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2021 AND 2020 (IN THOUSANDS)

	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from power billings to participants	$ 566,683	$ 586,915
Other cash receipts	1,133	1,113
Cash paid to suppliers	(277,106)	(347,683)
Net cash provided by operating activities	290,710	240,345
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	19,000	22,500
Debt issuance costs	(9)	(566)
Principal paid on long-term debt	(184,903)	(189,433)
Principal paid on commercial paper	(35,200)	(31,700)
Interest received (paid) on long-term debt and commercial paper	7,587	(8,790)
Additions to electric plant in service	(66,382)	(32,678)
Net cash used in capital and related financing activities	(259,907)	(240,667)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Purchases of investments	(149,822)	(8,279,934)
Proceeds from sales/maturities of investments	130,474	8,346,993
Interest earnings received on investments	1,500	3,325
Net cash (used in) provided by investing activities	(17,848)	70,384
NET INCREASE IN CASH AND CASH EQUIVALENTS	12,955	70,062
CASH AND CASH EQUIVALENTS:		
Beginning balance	72,573	2,511
Ending balance	$ 85,528	$ 72,573

See notes to financial statements.

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2021 AND 2020 (IN THOUSANDS)

	2021	2020
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 224,024	$ 101,434
Other non-operating income	1,133	1,113
Depreciation and amortization	122,095	136,032
Financing expenses, net of amortization of bond discount and refunding charge on defeasance of debt	(425)	(621)
Changes in operating assets and liabilities:		
Receivable from participants	(6,591)	1,203
Fuel inventories	16,347	(28,247)
Materials and supplies	(440)	(1,525)
Other current assets	(371)	(962)
Prepaid/accrued personnel services contract costs	(94,249)	14,968
Other liabilities	(1,942)	714
Accounts payable and accrued liabilities	14,698	(13,637)
Accrued credit to participants	14,813	30,705
Other assets	(557)	(710)
Deferred outflows of resources - other	190	(614)
Deferred inflows of resources - other	1,985	492
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 290,710	$ 240,345

SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:

Accounts payable and accrued liabilities included $4,577 and $2,705 at June 30, 2021 and 2020, respectively, of accruals for additions to electric plant in service.

See notes to financial statements.

(Concluded)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Purpose – Intermountain Power Agency (IPA), a separate legal entity and political subdivision of the State of Utah, was formed in 1977 by an Organization Agreement pursuant to the provisions of the Utah Interlocal Co-operation Act. IPA's membership consists of 23 municipalities which are suppliers of electric energy in the State of Utah. IPA's purpose is to own, acquire, construct, finance, operate, maintain, repair, administer, manage and control a facility to generate electricity located in Millard County, Utah and transmission systems through portions of Utah, Nevada and California (the "Project"). The operation and maintenance, along with construction of certain capital improvements of the Project are managed for IPA by the Department of Water and Power of the City of Los Angeles (LADWP) in its capacity as Operating Agent and Project Manager, respectively, pursuant to agreements. LADWP has also contracted to purchase a portion of the electric energy generated from the Project (see Note 11). Personnel at the generating plant are employed by Intermountain Power Service Corporation (IPSC), a separate legal non-governmental entity. IPSC is not a component unit of IPA. However, under a Personnel Services Contract ("PSC") between IPA and IPSC, IPA is required to pay all costs incurred by IPSC, including employee pensions and other postretirement benefits offered by IPSC to its employees. IPA's contractual rights and obligations under the PSC for IPSC's employee pensions and other postretirement benefits resulted in non-current assets of approximately $30,007,000 as of June 30, 2021 and non-current liabilities of approximately $64,242,000 as of June 30, 2020, as reported in the accompanying statements of net position. For the years ended June 30, 2021 and 2020, the accompanying statements of revenues and expenses and changes in net position includes a benefit of approximately $86,449,000 and expense of $44,968,000, respectively, within operation expense related to changes in these reported contractual amounts.

Use of Estimates in Preparing Financial Statements – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Basis of Accounting – IPA maintains its records substantially in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts, as required by its Contracts (see Note 11), and in conformity with U.S. GAAP. IPA applies all of the pronouncements of the Governmental Accounting Standards Board (GASB).

Utility Plant – Electric plant in service is stated at cost, which represents the actual direct cost of labor, materials, and indirect costs, including interest and other overhead expenses, net of related income during the construction period. Depreciation of electric plant in service is computed using the straight-line method over the estimated useful lives of the assets which range from five to 50 years.

Payments-in-Aid of Construction – IPA and the Southern California Public Power Authority (SCPPA), which is comprised of certain California Purchasers (see Note 9), have entered into the Southern Transmission System Agreement, as amended, ("STS Agreement") whereby SCPPA has made payments-in-aid of construction accumulating to approximately $737,900,000 as of June 30, 2021 and 2020, to IPA for costs associated with the acquisition, construction and improvements of the Southern Transmission System of the Project ("STS"). Such payments-in-aid are recorded as reductions to utility plant. IPA has also entered into inter-connection agreements with other entities that have made additional payments-in-aid of construction accumulating to approximately $2,037,000 as of June 30, 2021 and 2020.

Cash and Cash Equivalents – IPA considers short-term investments with an original maturity of three months or less to be cash equivalents. As more fully discussed in Note 5, the IPA Bond Resolution required the establishment of certain funds and prescribes the use of monies in these funds. Accordingly, the assets held in certain of these funds are classified as restricted in the accompanying statements of net position. Such restricted amounts are considered cash equivalents for purposes of the statements of cash flows.

Investments – The IPA Bond Resolution, as amended, stipulates IPA may invest in any securities, obligations or investments that are permitted by Utah Law. Investments are held by IPA as beneficial owner in book-entry form. Management believes there were no investments held by IPA during the years ended June 30, 2021 and 2020 that were in violation of the requirements of the IPA Bond Resolution.

Investments are stated at fair value in accordance with GASB Statement No. 72, *Fair Value Measurement and Application*. Accordingly, the change in fair value of investments is recognized as an increase or decrease to investment assets in the statements of net position and as earnings on investments in the statements of revenues and expenses and changes in net position.

Fuel Inventories, Materials and Supplies – Fuel inventories for the Project, principally coal, which have been purchased for the operation of the utility plant are stated at cost (computed on a last-in, first-out basis). The replacement cost of Project fuel inventory is approximately $20,318,000 and $23,472,000 greater than the stated last-in, first-out value at June 30, 2021 and 2020, respectively. Materials and supplies are stated at average cost.

Unamortized Bond Discount and Refunding Charge on Defeasance of Debt – Unamortized discount related to the issuance of bonds and the unamortized refunding charge related to the refunding of certain bonds are deferred and amortized using the interest method over the terms of the respective bond issues. Bonds payable have been reported net of the unamortized bond discount in the accompanying statements of net position. Unamortized refunding charge is reported as a deferred outflow of resources.

Net Costs Billed to Participants Not Yet Expensed – Billings to participants are designed to recover power costs as set forth by the Power Sales Contracts (see Note 11), which principally include current operating expenses, scheduled debt principal and interest, and deposits into certain funds. Pursuant to GASB Statement No. 62 related to regulated operations, net costs billed to participants not yet expensed in accordance with U.S. GAAP or expenses recognized but not currently billable under the Contracts are recorded as net costs billed to participants not yet expensed (a deferred inflow) or deferred as net costs to be recovered from future billings to participants (an asset), respectively, in IPA's statements of net position. In future periods, the deferred inflow will be settled, or the asset will be recovered as the associated expenses are recognized in accordance with U.S. GAAP or when they become billable Project costs in future participant billings, respectively. At June 30, 2021 and 2020, total accumulated Project costs billed to participants to date exceeded accumulated U.S. GAAP expenses, resulting in a deferred inflow, net costs billed to participants not yet expensed (see Note 4). Over the life of the Power Sales Contracts, aggregate U.S. GAAP expenses will equal aggregate billable power costs.

California has enacted legislation prohibiting its municipally owned electric utilities from entering into new long-term financial commitments for base-load generation that do not meet certain greenhouse gases emissions performance standards. During August 2018, the California Legislature passed legislation stating California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. The Environmental Protection Agency (EPA) has also proposed regulation of certain greenhouse gases emissions. Future federal and state legislative and regulatory action may also result from the increasing national and international attention to climate change. Legislative and regulatory actions, both nationally and in California, have had and may yet have significant (yet hard to quantify) effects on IPA and the Purchasers (see Note 11). If these effects, which are not currently determinable, were to cause the Purchasers to be unable to meet their future power sales contract payment obligations, IPA may then be required to remove assets and liabilities recognized pursuant to IPA's regulated operations from the statement of net position when the related application criteria is no longer met unless those costs continue to be recoverable through a separate regulatory billing. As of June 30, 2021, costs deferred are probable of recovery through future billings.

Long-Lived Assets – IPA evaluates the carrying value of long-lived assets based upon an evaluation of indicators of impairment including evidence of physical damage, enactment or approval of laws and regulations, technological developments, changes in the manner or expected duration of use of a long-lived asset, and changes in demand. A long-lived asset that is potentially impaired is then tested to determine whether the magnitude of the decline in service utility is significant and unexpected. Measurement of the amount of impairment, if any, is based upon a restoration cost approach, service units approach, or deflated depreciated replacement cost approach, or the difference between carrying value and fair value.

Pension and Other Postretirement Obligations – IPA sponsors a defined benefit pension plan and a postretirement medical plan that are accounted for pursuant to GASB Statement No. 68, *Accounting and Financial Reporting for Pensions—an amendment of GASB Statement No. 27,* and GASB Statement No. 75*, Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, respectively. No disclosures related to these plans are presented herein because amounts are not significant to the financial statements.

Asset Retirement Obligations – IPA records asset retirement obligations when the liability associated with the retirement of its tangible long-lived assets is both incurred and reasonably estimable. The determination of when the liability is incurred is based on the occurrence of external laws, regulations, contracts, or court judgments, together with the occurrence of an internal event that obligates an entity to perform asset retirement activities. An asset retirement obligation is measured based on the best estimate of the current value of outlays expected to be incurred, including probability weighting of potential outcomes, with a deferred outflow of resources recognized at the amount of the corresponding liability upon initial measurement. The current value of an ARO is adjusted for the effects of general inflation or deflation at least annually. All relevant factors are evaluated at least annually to determine whether the effects of one or more of the factors are expected to significantly change the estimated asset retirement outlays. The deferred outflows of resources of asset retirement costs is amortized over the estimated useful life of the tangible capital assets. See Note 10 for additional information on IPA's asset retirement obligations.

Recently Adopted Accounting Pronouncements – In January 2017, the GASB issued Statement No. 84, *Fiduciary Activities*. This statement established criteria for identifying fiduciary activities of all state and local governments. An activity meeting the criteria should be reported in a fiduciary fund in the financial statements. This statement describes four fiduciary funds that should be reported, if applicable: (1) pension (and other employee benefit) trust funds, (2) investment trust funds, (3) private-purpose trust funds, and (4) custodial funds. IPA adopted this statement during the year ended June 30, 2021, the adoption of which did not have a material effect on the financial statements.

Recently Issued Accounting Pronouncements – In June 2017, the GASB issued Statement No. 87, *Leases.* This statement requires recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and as inflows of resources or outflows of resources recognized based on the payment provisions of the contract. It establishes a single model for lease accounting based on the principle that leases are financings of the right to use an underlying asset. A lessee is required to recognize a lease liability and an intangible right-to-use asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources, thereby enhancing the relevance and consistency of information about an entity's leasing activities. This statement is effective for financial statements for years beginning after June 15, 2021. IPA is currently evaluating the effects the adoption of this statement will have on the financial statements.

2. UTILITY PLANT

Utility plant activity for the years ended June 30, 2021 and 2020, is as follows (in thousands):

	July 1, 2020	Increases	Decreases	June 30, 2021
Utility plant not being depreciated -				
Construction work-in-progress	$ 39,246	$ 31,595	$ (15,977)	$ 54,864
Land and land rights	113,823	-	-	113,823
Total	153,069	31,595	(15,977)	168,687
Utility plant being depreciated/amortized:				
Production	2,826,644	13,347	(1,440)	2,838,551
Transmission	832,239	38,635	(10,612)	860,262
Payments-in-aid of construction - transmission	(739,937)	-	-	(739,937)
General	52,679	649	(80)	53,248
Total	2,971,625	52,631	(12,132)	3,012,124
Accumulated depreciation	(2,926,888)	(145,752)	12,132	(3,060,508)
Accumulated amortization of payments-in-aid of construction	521,446	50,400	-	571,846
Total accumulated depreciation	(2,405,442)	(95,352)	12,132	(2,488,662)
Utility plant - net	$ 719,252	$ (11,126)	$ (15,977)	$ 692,149

	July 1, 2019	Increases	Decreases	June 30, 2020
Utility plant not being depreciated -				
Construction work-in-progress	$ 14,591	$ 24,655	$ -	$ 39,246
Land and land rights	113,823	-	-	113,823
Total	128,414	24,655	-	153,069
Utility plant being depreciated/amortized:				
Production	2,824,710	2,283	(349)	2,826,644
Transmission	825,836	7,090	(687)	832,239
Payments-in-aid of construction - transmission	(739,937)	-	-	(739,937)
General	52,173	573	(67)	52,679
Total	2,962,782	9,946	(1,103)	2,971,625
Accumulated depreciation	(2,785,890)	(142,101)	1,103	(2,926,888)
Accumulated amortization of payments-in-aid of construction	488,936	32,510	-	521,446
Total accumulated depreciation	(2,296,954)	(109,591)	1,103	(2,405,442)
Utility plant - net	$ 794,242	$ (74,990)	$ -	$ 719,252

3. CASH, CASH EQUIVALENTS AND INVESTMENTS

Cash, cash equivalents and investments consist of the following at June 30, 2021 and 2020 (in thousands):

	2021		2020	
	Fair Value	Weighted Average Remaining Maturity	Fair Value	Weighted Average Remaining Maturity
Cash and cash equivalents:				
Restricted:				
Money market funds	$ -		$ 739	1 day or less
Cash	55,699	1 day or less	4,195	1 day or less
Total restricted	55,699		4,934	
Current:				
Money market funds	20,000	1 day or less	65,246	1 day or less
Cash	9,829	1 day or less	2,393	1 day or less
Total current	29,829		67,639	
Total cash and cash equivalents	$ 85,528		$ 72,573	
Investments:				
Restricted:				
U.S. Treasuries	$ -		$ 2,615	0.04 years
U.S. Agencies	2,076	0.04 years	4,497	0.48 years
Commercial paper	5,198	1 day or less	20,896	1 day or less
Corporate bonds	4,056	0.35 years	14,082	1.27 years
Total restricted	11,330		42,090	
Current:				
U.S. Agencies	25,901	1.59 years	20,184	2.25 years
Commercial paper	34,675	0.32 years	-	
Corporate bonds	100,849	1.45 years	91,229	1.37 years
Total current	161,425		111,413	
Total investments	$ 172,755		$ 153,503	

Investments consist entirely of U.S. Government Agencies, U.S. Treasuries, commercial paper and corporate bonds whose fair value is derived from inputs using observable market data to estimate current interest rates.

Interest Rate Risk – Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. In accordance with its investment policy, IPA manages its exposure to interest rate risk by requiring that the remaining term to maturity of investments not exceed the date the funds will be required to meet cash obligations.

Credit Risk – Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. In accordance with its investment policy, IPA manages its exposure to credit risk by limiting its investments to securities authorized for investment of public funds under the Utah Money Management Act, which requires a rating of "A" or higher or the equivalent of "A" or higher by two nationally recognized statistical rating organizations.

Custodial Credit Risk – Cash Deposits – Custodial credit risk is the risk that, in the event of a failure of the counterparty holding the funds, IPA's deposits may not be returned. IPA does not require deposits to be fully insured and collateralized. As of June 30, 2021, approximately $65,528,000 of IPA's bank balances are uninsured and uncollateralized.

Fair Value Measurements – IPA measures and records its investments using fair value measurement guidelines established by U.S. GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows:

Level 1 – Quoted prices for identical investments in active markets;
Level 2 – Observable inputs other than quoted market prices; and,
Level 3 – Valuations derived from unobservable inputs.

At June 30, 2021 and 2020, IPA's fair value measurements and their levels within the fair value hierarchy were as follows (in thousands):

	2021			
	Level 1	**Level 2**	**Level 3**	**Total**
Investments by fair value level:				
U.S. Agencies	$ -	$ 27,977	$ -	$ 27,977
Commercial paper	-	39,873	-	39,873
Corporate bonds	-	104,905	-	104,905
Total investments by fair value level	$ -	$ 172,755	$ -	$ 172,755

	2020			
	Level 1	**Level 2**	**Level 3**	**Total**
Investments by fair value level:				
U.S. Treasuries	$ -	$ 2,615	$ -	$ 2,615
U.S. Agencies	-	24,681	-	24,681
Commercial paper	-	20,896	-	20,896
Corporate bonds	-	105,311	-	105,311
Total investments by fair value level	$ -	$ 153,503	$ -	$ 153,503

4. NET COSTS BILLED TO PARTICIPANTS NOT YET EXPENSED

Net costs billed to participants not yet expensed for the years ended June 30, 2021 and 2020 and the accumulated totals as of June 30, 2021 and 2020, consisted of the following (in thousands):

	For the Years Ended June 30,		Accumulated Totals as of June 30,	
	2021	2020	2021	2020
Items in accordance with U.S. GAAP not billable to participants under the power sales contracts:				
Interest expense in excess of amounts billable	$ -	$ -	$ (452,454)	$ (452,454)
Depreciation and amortization expense	(122,095)	(136,032)	(2,825,915)	(2,703,820)
Amortization of bond discount and refunding on defeasance of bonds	(11,494)	(17,129)	(1,364,148)	(1,352,654)
Accretion of interest on zero coupon bonds	-	-	(349,408)	(349,408)
Charge on retired debt	-	-	(157,653)	(157,653)
Cumulative effect of a change in accounting principle	-	-	(18,241)	(18,241)
Accretion of asset retirement obligations	-	-	(26,965)	(26,965)
Unrealized gains on investments	82	443	145	63
Change in fair value of interest rate exchange agreements	-	-	(27,652)	(27,652)
Gain on sale of ownership interest in coal mines	-	-	4,877	4,877
Amortization of deferred fuel costs	-	-	(69,379)	(69,379)
Accrued interest earnings	(83)	(478)	(9,211)	(9,128)
Change in liabilities and other	100,386	(1,966)	1,326	(99,060)
Amounts billed to participants under the bond resolution and the power sales contracts:				
Bond and subordinated note principal	221,191	222,245	4,900,052	4,678,861
Deferred fuel costs	-	-	32,228	32,228
Capital improvements	34,531	14,410	585,882	551,351
Reduction of required fund deposits	136	70	4,096	3,960
Cash received from sale of assets	-	-	(18,904)	(18,904)
Participant funds expended for debt reduction, refinancing and/or other financing costs (Note 11)	-	-	310,380	310,380
Net costs billed to participants not yet expensed	$ 222,654	$ 81,563	$ 519,056	$ 296,402

5. BONDS PAYABLE

To finance the construction of the Project, IPA has sold Revenue and Revenue Refunding Bonds (the "Senior Bonds") pursuant to IPA's Power Supply Revenue Bond Resolution adopted September 28, 1978, as amended and supplemented (the "Bond Resolution") and IPA has sold Subordinated Revenue Refunding Bonds (the "Subordinated Bonds") pursuant to IPA's Subordinated Power Supply Revenue Resolution adopted March 4, 2004, as supplemented (the "Subordinated Bond Resolution"). There are no Senior Bonds outstanding as of June 30, 2021 and 2020. As of June 30, 2021 and 2020, for Subordinated Bonds (collectively, the "Bonds") the principal amount consisted of the following (in thousands):

Series	Bonds Dated	Final Maturity on July 1	2021	2020
Subordinated Bonds				
2018 A	4/4/2018	2023	$ 82,830	$ 105,230
Unamortized bond premium			1,262	3,749
Current maturities of Bonds payable			(44,030)	(22,400)
Long-term portion of bonds payable - net			$ 40,062	$ 86,579

Interest rates on the Bonds payable outstanding were 5.00% at June 30, 2021 and ranged from 2.75% to 5.00% at June 30, 2020.

The changes in the par value of Bonds payable for the years ended June 30, 2021 and 2020, are as follows (in thousands):

	2021	2020
Beginning balance	$ 105,230	$ 129,340
Deductions - Principal maturities	(22,400)	(24,110)
Ending balance	$ 82,830	$ 105,230

The principal amounts of future maturities, sinking fund requirements and interest to be paid for the Bonds outstanding as of June 30, 2021, are as follows (in thousands):

	Principal	Interest
Years ending June 30:		
2022	$ 44,030	$ 3,041
2023	34,185	1,085
2024	4,615	115
Total	$ 82,830	$ 4,241

The Subordinated Bond Resolution stipulates that the Subordinated Bonds are direct and special obligations of IPA payable from and secured by amounts on deposit in the Subordinated Indebtedness Debt Service Account. The Bond Resolution and the Subordinated Bond Resolution require that after providing for monthly operating expenses and the required monthly deposits of revenues have been made to the Debt Service Fund that revenues in amounts sufficient to provide for the debt service requirements of Subordinated Bonds be deposited each month into the Subordinated Indebtedness Debt Service Account. The security for the Subordinated Bonds has the same priority as the security for the commercial paper notes (see Note 7) and is senior to the security for the subordinated notes payable.

Funds Established by the Bond Resolution – The Bond Resolution requires that certain funds be established to account for IPA's receipts and disbursements and stipulates the use of monies, investments held in such funds and balances that are to be maintained in certain of the funds. Balances in the other funds are determined by resolution of the IPA Board of Directors. A summary of funds established by the Bond Resolution and the aggregate amount of assets held in these funds, including accrued interest receivable as of June 30, 2021 and 2020, is as follows (in thousands):

	2021	2020
Restricted assets:		
Subordinated Indebtedness Fund:		
Debt Service Account	$ 60,095	$ 39,251
Debt Service Reserve Account	1,531	2,345
Construction Fund:		
Tax Exempt Account	761	740
Taxable Account	9	29
Self-Insurance Fund	4,649	4,659
Total restricted assets	67,045	47,024
Revenue Fund (Note 11)	191,376	179,346
Total	$ 258,421	$ 226,370

The reconciliation of the current assets as reported in the accompanying statements of net position to the Revenue Fund at June 30, 2021 and 2020, is as follows (in thousands):

	2021	2020
Current assets reported in statements of net position:		
Cash and cash equivalents	$ 29,829	$ 67,639
Investments	161,425	111,413
Interest receivable	122	294
Revenue Fund	$ 191,376	$ 179,346

Covenants – The Bond Resolution has imposed certain covenants upon IPA which, among others, include a promise to establish rates sufficient to pay the bondholders scheduled interest and principal payments and to make such payments on a timely basis, keep proper books of record and account, and comply with certain financial reporting and auditing requirements. IPA believes that it is in compliance with all covenants as of June 30, 2021 and 2020.

Defeasance of Debt – No bonds were defeased during the years ended June 30, 2021 and 2020.

6. SUBORDINATED NOTES PAYABLE

IPA and the California Purchasers (see Note 11) have entered into the Intermountain Power Project Prepayment Agreement ("Prepayment Agreement"). Pursuant to the Prepayment Agreement, a California Purchaser, upon providing IPA sufficient funds, can direct IPA to defease certain IPA outstanding Bonds. In consideration for IPA's use of the California Purchaser's funds to defease such outstanding Bonds, IPA issues to the California Purchaser a subordinated note or notes payable. Such subordinated notes payable are not subject to early redemption by IPA and are not transferable by the holder, but otherwise carry terms substantially equivalent to the defeased Bonds (subject to certain adjustments, some of which can result in negative interest) and are junior and subordinate to Bonds payable and commercial paper notes. As of June 30, 2021 and 2020, the principal amount of interest bearing subordinated notes payable consisted of the following (in thousands):

Note Holder	Issue Date	Final Maturity on July 1	2021	2020
LADWP	2/10/2000	2021	$ 2,534	$ 35,650
LADWP	3/2/2000	2023	142,538	221,067
LADWP	5/2/2000	2021	4,025	48,300
City of Pasadena	1/29/2009	2023	8,047	14,630
Total subordinated notes payable			157,144	319,647
Unamortized discount			(2,237)	(4,974)
Current maturities of subordinated notes payable			(74,971)	(162,503)
Long-term portion of subordinated notes payable			$ 79,936	$ 152,170

The changes in the par value of subordinated notes payable for the years ended June 30, 2021 and 2020, are as follows (in thousands):

	2021	2020
Beginning balance	$ 319,647	$ 484,970
Deductions - principal maturities	(162,503)	(165,323)
Ending balance	$ 157,144	$ 319,647

The principal amounts of future maturities and interest to be paid (received) on subordinated notes payable as of June 30, 2021, are as follows (in thousands):

	Principal	Interest
Years ending June 30:		
2022	$ 74,971	$ (13,783)
2023	75,791	(4,960)
2024	6,382	(53)
Total	$ 157,144	$ (18,796)

7. COMMERCIAL PAPER NOTES

An amended subordinated indebtedness resolution allows IPA to currently issue commercial paper notes in amounts not to exceed $100,000,000 outstanding at any one time. The remaining maturities of commercial paper notes were extinguished between August 2020 and March 2021 leaving $0 outstanding at June 30, 2021. The commercial paper notes outstanding at June 30, 2020 of $35,200,000 bore interest between .18% and 1.35% with remaining maturities ranging between 1 and 78 days.

IPA entered into certain credit agreements with third parties equal to the outstanding principal portion of the commercial paper notes. The credit agreements would have provided funds, if required, to pay the outstanding principal of the commercial paper notes. The credit agreements, if utilized, would have created subordinated bank notes. There were no borrowings under these agreements and as of June 30, 2021, have been terminated.

8. TRANSITION PROJECT INDEBTEDNESS

On November 25, 2019, IPA and the Purchasers approved a Plan of Finance for funding renewal project activities that anticipates using shorter-term bridge financing in early project stages followed by long-term financing as required to fund anticipated costs to complete construction. On December 27, 2019, IPA amended its subordinated indebtedness resolution to allow IPA to issue subordinated indebtedness not to exceed $100,000,000 for the purpose of providing a portion of the monies necessary to pay the Cost of Acquisition and Construction of the Gas Repowering (as defined in the Power Sales Contracts). These subordinated bonds are designated by the title “Subordinated Power Supply Revenue Bonds, 2019 Drawdown Series” (the “Drawdown Bonds”) and deemed to constitute Transition Project Indebtedness as defined by the Power Sales Contracts. The Drawdown Bonds were issued by Royal Bank of Canada (RBC) on December 30, 2019, in two subseries, designated as Tax-Exempt and Taxable. The Drawdown Bonds issued and outstanding at June 30, 2021 were $38,000,000 and $3,500,000 and bore interest at 0.41% and 0.69% in the Tax-Exempt and Taxable subseries, respectively. The Drawdown Bonds issued and outstanding at June 30, 2020 were $20,350,000 and $2,150,000 and bore interest at 0.52% and 0.78% in the Tax-Exempt and Taxable subseries, respectively. The Drawdown Bonds are to be terminated and repaid on or before December 29, 2022. Should any principal of Drawdown Bonds not be repaid on or before December 29, 2022, the principal will be redeemed through installment payments during an amortization period that ends on December 29, 2027. No payments of principal were made during the years ended June 30, 2021 and 2020. IPA has established separate cash and investment accounts for each of the subseries of the Drawdown Bonds.

9. ADVANCES FROM SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

In accordance with the STS Agreement, SCPPA has funded an allocable portion of certain of IPA’s reserves. Management believes that advances from SCPPA in the accompanying financial statements meet those required under and are co-terminus with the STS Agreement.

10. ASSET RETIREMENT OBLIGATIONS

IPA's transmission facilities are generally located upon land that is leased from Federal and certain state governments. Upon termination of the leases, the structures, improvements and equipment are to be removed and the land is to be restored. Because these leases are expected to be renewed indefinitely and because of the inherent value of the transmission corridors, the leases have no foreseeable termination date and, therefore, IPA has no asset retirement obligations (AROs) recorded related to the transmission facilities. IPA does have certain AROs related to other long-lived assets at or near the generation station site resulting from applicable laws and regulations. These obligations are related to the reclamation of certain rights-of-way, wastewater ponds, settling ponds, landfills and other facilities that may affect ground water quality.

On August 6, 2019, the IPA Board and Intermountain Power Project (IPP) Coordinating Committee formally approved the Retirement Plan for the decommissioning and retirement of the existing facilities that are not to be used for the generation or transmission of power pursuant to the Contracts or the Renewal Contracts, which created a contractual requirement to retire certain capital assets under the Renewal Contracts. This resulted in an additional $96,424,000 for the retirement and dismantling of existing generating station assets and $37,166,000 for the retirement and dismantling of existing converter station assets, which were recorded as asset retirement obligations during the year ended June 30, 2020.

As of June 30, 2021 and 2020, the current value of IPA's asset retirement obligations totaled approximately $273,242,000 and $259,243,000, respectively. The current value of AROs are generally estimated based on decommissioning cost studies performed by third-party experts. The increase in the current value of AROs of approximately $13,999,000 during the year ended June 30, 2021, is due to the effects of general inflation.

11. POWER SALES AND POWER PURCHASE CONTRACTS

IPA has sold the entire capacity of the Project pursuant to Power Sales Contracts, as amended (the "Contracts"), to 35 utilities consisting of six California municipalities ("California Purchasers"), 23 Utah municipalities ("Utah Municipal Purchasers") and six rural electrical cooperatives ("Cooperative Purchasers") (collectively, the "Purchasers"). The California Purchasers, Utah Municipal Purchasers and the Cooperative Purchasers have contracted to purchase approximately 79%, 14%, and 7%, respectively, of the capacity of the Project. The Contracts expire on June 15, 2027. As long as any of the Bonds are outstanding, the Contracts cannot be terminated nor amended in any manner which will impair or adversely affect the rights of the bondholders. Under the terms of the Contracts, the Purchasers are obligated to pay their proportionate share of all operation and maintenance expenses and debt service on the Bonds and any other debt incurred by IPA, whether or not the Project or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, reduced, or terminated. In accordance with the Contracts, billings in excess of monthly power costs, as defined, are credited to Purchasers taking power in any fiscal year (the "Participants"). IPA recorded credits to Participants in operating revenue of approximately $51,091,000 and $36,278,000 for the years ended June 30, 2021 and 2020, respectively. Such credits to Participants are applied in the subsequent year to reduce power billings in accordance with the Contracts.

As part of IPA's strategic planning initiatives, IPA and the Purchasers executed the Second Amendatory Power Sales Contracts which provides that the Project be repowered and that IPA offer the Purchasers renewal in their generation and associated transmission entitlements through the Renewal Power Sales Contracts (the "Renewal Contracts"). IPA and 32 of the Purchasers entered into Renewal Contracts, which became effective on January 16, 2017. Two renewing California Purchasers subsequently provided a notice of termination of their Renewal Contracts to IPA effective November 1, 2019. The 50-year term of the Renewal Contracts is to commence upon termination of the Contracts.

On September 24, 2018, IPA and the Purchasers approved changes to the repowering that constituted an Alternative Repowering under the Contracts. The Alternative Repowering is described to include the construction and installation of two combined-cycle natural gas fired power blocks, each block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW.

A Bond Retirement and Financing Account ("BRFA") was established by the Forty-First Supplemental Power Supply Revenue Bond Resolution (the "Forty-First Supplemental Resolution"). Amounts deposited into the BRFA are held in the Revenue Fund and are to be used to purchase, redeem or defease outstanding IPA debt; for contributions required to be made by IPA in refunding bond issues; or for other financing costs since the BRFA was established. The remaining BRFA funds totaled approximately $40,017,000 and $59,223,000 as of June 30, 2021 and 2020, respectively.

12. RELATED PARTY TRANSACTIONS

LADWP, as Operating Agent, performed engineering and other services for the Project totaling approximately $35,660,000 and $32,994,000 for the years ended June 30, 2021 and 2020, respectively, which has been billed to IPA and charged to operations or utility plant, as appropriate. Operating Agent unbilled costs totaling approximately $4,415,000 and $3,815,000 are included in accounts payable at June 30, 2021 and 2020, respectively.

Power sales to LADWP for the years ended June 30, 2021 and 2020, totaled approximately $401,921,000 and $385,955,000, respectively. The receivable from LADWP at June 30, 2021 and 2020, was approximately $4,233,000 and $530,000, respectively. Power sales to the City of Anaheim for the years ended June 30, 2021 and 2020, totaled approximately $82,873,000 and $81,370,000, respectively. The receivable from the City of Anaheim at June 30, 2021 and 2020, was approximately $1,600,000 and $151,000, respectively. No other individual purchasers are over 10% of generation entitlement.

Subordinated notes payable have been issued to LADWP (see Note 6). Interest (income) expense on these subordinated notes payable of approximately ($11,852,000) and $1,030,000 has been recorded for the years ended June 30, 2021 and 2020, respectively, of which approximately $519,000 and $201,000 was payable at June 30, 2021 and 2020, respectively.

Subordinated notes payable have been issued to the City of Pasadena (see Note 6). Interest income on these subordinated notes payable of approximately $503,000 and $196,000 has been recorded for the years ended June 30, 2021 and 2020, respectively, of which approximately $24,000 and $13,000 was receivable at June 30, 2021 and 2020, respectively.

13. COMMITMENTS AND CONTINGENCIES

Coal Supply – At June 30, 2021, IPA was obligated under short and long-term take-or-pay coal supply contracts for the purchase of coal. The cost of coal is computed at a base price per ton, adjusted periodically for various price and quality adjustments and includes transportation to the plant. The contracts require minimum purchases of coal over the lives of the contracts, exclusive of events of force majeure, as follows (computed using the current price under the contracts, in thousands):

Years ending June 30:	
2022	$ 167,039
2023	157,739
2024	157,739
2025	78,870
Thereafter	-
	$ 561,387

The actual cost of coal purchases under the coal supply contracts for the years ended June 30, 2021 and 2020, was approximately $148,191,000 and $181,867,000, respectively.

Clean Air Act New Source Review – IPA received from EPA in 2010 and 2011 requests for information, pursuant to Section 114 of the Clean Air Act ("CAA"), concerning the construction, modification and operation of the Project. IPA responded to these requests in 2010 to 2012, and later provided additional information in response to follow-up questions and requests from EPA. These Section 114 requests were part of a national enforcement initiative that EPA had undertaken under the CAA against owners and operators of electric generating facilities. EPA generally asserted that the industry failed to comply with the New Source Review provision of the CAA ("NSR"), arguing that facilities made certain physical or operational changes at their plants that should have resulted (or "triggered") additional regulatory requirements under the NSR program. With respect to IPA, EPA asserted that certain uprate projects undertaken at the station in 2002-2004 triggered NSR. On February 19, 2015, IPA received from Sierra Club a Notice of Intent to Sue under the CAA, also alleging that the uprate projects triggered NSR.

IPA met with EPA and the United States Department of Justice (DOJ) to discuss potential resolution of this investigation on several occasions since 2012, the last meeting taking place March 20, 2017. To date, EPA has not issued a notice of violation, or initiated other formal enforcement action against IPA with regard to this matter. Likewise, the Sierra Club has filed no lawsuit. If the government were to file an enforcement action, and/or if Sierra Club were to file a lawsuit under the citizen suit provisions of the CAA, either could request that the court order injunctive relief to require additional emissions control equipment at the facility and assess civil penalties. Under applicable regulations, civil penalties can be up to $37,500 per day for each violation that occurred before November 2, 2015; and up to $102,638 per day for each violation that occurred after November 2, 2015. IPA and the government entered into an agreement tolling the statute of limitations by six months starting February 15, 2012, which agreement was renewed on multiple occasions for additional, six-month terms. The last tolling agreement renewal expired on December 31, 2018, and the government did not request that it be renewed. In view of the government letting the tolling agreement lapse and given the lack of further engagement by the government and Sierra Club for over four years, it appears unlikely that any claims related to this matter will be asserted.

Other Litigation – IPA is also in other litigation arising from its operating activities. The probability or extent of unfavorable outcomes of these suits is not presently determinable.

California Greenhouse Gas Initiatives – For several years, California policy makers have sought to limit greenhouse gas emissions in California. Both the Los Angeles City Council and the State of California have adopted renewable portfolio standards, which, among other things required LADWP and the other California utilities to serve 33% and 50% of their load with renewable energy by 2020 and 2030, respectively. On September 29, 2006, California Senate Bill 1368 – An Act to Impose Greenhouse Gas Performance Standards on Locally Owned Public Utilities (SB 1368) was signed into law. SB 1368 was directed specifically at limiting greenhouse gas emissions associated with electric power consumed in California by prohibiting California electric providers from entering into long-term financial commitments for base load generation unless such generation complies with greenhouse gas emission performance standards. On September 10, 2018, California Senate Bill 100 (SB 100) was signed into law. SB 100 states California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. SB 100 also accelerates the existing target of 50% renewable energy by 2030, to 60% renewable energy by 2030. While these and other actions by California policy makers have the potential to impact IPA and its power purchasers, IPA does not believe that any of these initiatives will render existing Power Sales Contracts between IPA and the California Purchasers void, ineffective or unenforceable

Other Environmental Regulation – The EPA has proposed regulation of certain greenhouse gases emissions. Future federal and state legislative and regulatory action may also result from the increasing intensity of national and international attention to climate change. Legislative and regulatory actions, both nationally and in California, have had and may yet have significant (yet hard to quantify) effects on IPA and the Purchasers.

COVID-19 – In March 2020, COVID-19 was officially declared a pandemic and has been having significant effects in most markets and economies. IPA has not experienced any significant impact to its financial position and results of operations to date. However, the future impact of COVID-19 on IPA's financial position and

results of operations will depend on may factors, including: (i) the duration and spread of the outbreak, (ii) the restrictions and recommendations of health organizations and governments, (iii) the effects on the financial markets, and (iv) the effects in general on the economy. It is not possible to reasonably estimate the length and severity of these developments and the impact of COVID-19 on the financial conditions and results of operations of IPA in future periods.

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INTERMOUNTAIN POWER AGENCY

SUPPLEMENTAL SCHEDULE OF CHANGES IN FUNDS ESTABLISHED BY THE IPA REVENUE BOND RESOLUTION FOR THE YEARS ENDED JUNE 30, 2020 AND 2021 (IN THOUSANDS)

		Restricted Assets					
		Subordinated Indebtedness Fund		Construction Fund			
	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Tax Exempt Construction Account	Taxable Construction Account	Self-Insurance	Total
BALANCE, JULY 1, 2019	$ 174,993	$ 40,104	$ 2,951	$ -	$ -	$ 4,621	$ 222,669
ADDITIONS:							
Proceeds from issuance of Bonds	-	-	-	20,350	2,150	-	22,500
Power billings received	586,915	-	-	-	-	-	586,915
Other revenues	1,113	-	-	-	-	-	1,113
Investment earnings	4,074	(112)	10	10	2	39	4,023
Total	592,102	(112)	10	20,360	2,152	39	614,551
DEDUCTIONS:							
Operating expenditures	347,683	-	-	-	-	-	347,683
Capital expenditures	22,153	-	-	10,525	-	-	32,678
Interest paid on long-term debt and commercial paper	-	8,657	-	87	46	-	8,790
Principal paid on long-term debt	-	189,433	-	-	-	-	189,433
Principal paid on commercial paper	-	31,700	-	-	-	-	31,700
Debt issuance costs	360	-	-	204	2	-	566
Total	370,196	229,790	-	10,816	48	-	610,850
TRANSFERS:							
Transfer of revenues to other Funds	(229,009)	229,049	(43)	4	-	(1)	-
Other transfers	11,456	-	(573)	(8,808)	(2,075)	-	-
Total	(217,553)	229,049	(616)	(8,804)	(2,075)	(1)	-
BALANCE, JUNE 30, 2020	$ 179,346	$ 39,251	$ 2,345	$ 740	$ 29	$ 4,659	$ 226,370

(Continued)

INTERMOUNTAIN POWER AGENCY

SUPPLEMENTAL SCHEDULE OF CHANGES IN FUNDS ESTABLISHED BY THE IPA REVENUE BOND RESOLUTION FOR THE YEARS ENDED JUNE 30, 2020 AND 2021 (IN THOUSANDS)

		Restricted Assets					
		Subordinated Indebtedness Fund		Construction Fund			
	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Tax Exempt Construction Account	Taxable Construction Account	Self-Insurance	Total
BALANCE, JULY 1, 2020	$ 179,346	$ 39,251	$ 2,345	$ 740	$ 29	$ 4,659	$ 226,370
ADDITIONS:							
Proceeds from issuance of Bonds	-	-	-	17,650	1,350	-	19,000
Power billings received	566,683	-	-	-	-	-	566,683
Other revenues	1,133	-	-	-	-	-	1,133
Investment earnings	1,383	(76)	(51)	2	-	(10)	1,248
Total	569,199	(76)	(51)	17,652	1,350	(10)	588,064
DEDUCTIONS:							
Operating expenditures	277,106	-	-	-	-	-	277,106
Capital expenditures	47,707	-	-	18,675	-	-	66,382
Interest paid (received) on long-term debt and commercial paper	-	(7,904)	-	269	48	-	(7,587)
Principal paid on long-term debt	-	184,903	-	-	-	-	184,903
Principal paid on commercial paper	-	35,200	-	-	-	-	35,200
Debt issuance costs	-	-	-	9	-	-	9
Total	324,813	212,199	-	18,953	48	-	556,013
TRANSFERS:							
Transfer of revenues to other Funds	(213,150)	213,090	60	-	-	-	-
Other transfers	(19,206)	20,029	(823)	1,322	(1,322)	-	-
Total	(232,356)	233,119	(763)	1,322	(1,322)	-	-
BALANCE, JUNE 30, 2021	$ 191,376	$ 60,095	$ 1,531	$ 761	$ 9	$ 4,649	$ 258,421

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APPENDIX D

INTERMOUNTAIN POWER AGENCY

Unaudited Interim Financial Information of the Agency as of and for the Six Months Ended December 31, 2021 and 2020

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
DECEMBER 31, 2021 AND 2020 (IN THOUSANDS - UNAUDITED)

ASSETS	2021	2020
UTILITY PLANT:		
Electric plant in service	$ 3,189,224	$ 3,141,342
Less accumulated depreciation	(2,546,697)	(2,451,636)
Net	642,527	689,706
RESTRICTED ASSETS:		
Cash and cash equivalents	2,287	1,915
Investments	34,696	25,109
Interest receivable	31	17
Total	37,014	27,041
OTHER NON-CURRENT ASSETS		
Prepaid personnel services contract costs	30,007	-
Other	2,579	2,022
Total	32,586	2,022
Total Non-Current Assets	712,127	718,769
CURRENT ASSETS:		
Cash and cash equivalents	32,176	55,388
Investments	131,116	129,662
Interest receivable	1,465	199
Receivable from participants	367	4,225
Fuel inventories	18,628	54,172
Materials and supplies	23,537	22,186
Other	10,342	10,811
Total Current Assets	217,631	276,643
Total Assets	929,758	995,412
DEFERRED OUTFLOWS OF RESOURCES:		
Unamortized refunding charge	5,166	13,324
Unamortized asset retirement costs	111,545	125,153
Other	1,678	1,868
Total Deferred Outflows of Resources	118,389	140,345
TOTAL ASSETS AND DEFERRRED OUTFLOWS OF RESOURCES	$ 1,048,147	$ 1,135,757

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
DECEMBER 31, 2021 AND 2020 (IN THOUSANDS - UNAUDITED)

LIABILITIES	2021	2020
LONG-TERM PORTION OF BONDS PAYABLE - Net	$ -	$ 41,305
LONG TERM PORTION OF SUBORDINATED NOTES PAYABLE -Net	43,125	112,097
LONG-TERM DRAW DOWN BONDS	48,500	34,500
ADVANCES FROM SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY	10,930	10,930
OTHER NON-CURRENT LIABILITIES:		
Personnel services contract and other obligations	-	64,242
Asset retirement obligations	273,242	259,243
Other	1,854	3,796
Total	275,096	327,281
CURRENT LIABILITIES:		
Commercial paper notes	-	9,941
Current maturities of bonds payable	-	44,030
Current maturities of subordinated notes payable	71,029	122,436
Interest payable	-	904
Accrued credit to participants	56,858	61,272
Accounts payable and accrued liabilities	28,862	26,777
Total Current Liabilities	156,749	265,360
COMMITMENTS AND CONTINGENT LIABILITIES	-	-
Total Liabilities	534,400	791,473
DEFERRED INFLOWS OF RESOURCES		
Net costs billed to participants not yet expensed	$ 510,066	$ 342,589
Other	3,681	1,695
Total Deferred Inflows of Resources	513,747	344,284
TOTAL LIABILITIES AND DEFERRRED INFLOWS OF RESOURCES	$ 1,048,147	$ 1,135,757

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INTERMOUNTAIN POWER AGENCY

STATEMENTS OF REVENUES AND EXPENSES
FOR THE SIX MONTHS ENDED DECEMBER 31, 2021 AND 2020 (IN THOUSANDS - UNAUDITED)

	2021	2020
OPERATING REVENUES:		
Power sales to participants	$ 261,286	$ 310,304
Less credit to participants	(40,731)	(61,414)
Net revenues	220,555	248,890
OPERATING EXPENSES:		
Fuel	98,947	96,119
Operation	36,028	18,917
Maintenance	19,293	23,374
Depreciation and amortization	72,804	60,098
Taxes and payment in lieu of taxes	6,842	8,269
Total expenses	233,914	206,777
OPERATING INCOME (LOSS)	(13,359)	42,113
NONOPERATING INCOME	242	120
INTEREST CHARGES:		
Interest on bonds and subordinated notes, and other debt	(8,423)	(9,061)
Financing expenses (principally amortization of bond discount and refunding charge on defeasance of debt)	3,357	5,905
Charge on defeasance of debt	814	-
Earnings on investments	125	(798)
Total interest charges	(4,127)	(3,954)
NET COSTS (RECOVERED FROM) BILLED TO PARTICIPANTS NOT YET EXPENSED	(8,990)	46,187
CHANGE IN NET POSITION	$ -	$ -

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE SIX MONTHS ENDED DECEMBER 31, 2021 AND 2020 (IN THOUSANDS - UNAUDITED)

	2021	2020
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from power billings to participants	$ 233,849	$ 270,962
Other cash receipts	242	120
Cash paid to suppliers	(164,557)	(156,565)
Net cash provided by operating activities	69,534	114,517
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from issuance of debt	7,000	12,000
Defeasance and retirement of bonds	(40,941)	-
Debt issuance costs	(4)	-
Principal paid on long-term debt	(85,471)	(103,908)
Principal paid on commercial paper	-	(25,259)
Interest received on long-term debt and commercial paper	5,045	7,127
Additions to electric plant in service	(12,986)	(19,355)
Net cash used in capital and related financing activities	(127,357)	(129,395)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Purchases of investments	(79,565)	(1,794,550)
Proceeds from sales/maturities of investments	85,861	1,793,342
Interest earnings received on investments	462	816
Net cash (used in) provided by investing activities	6,758	(392)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(51,065)	(15,270)
CASH AND CASH EQUIVALENTS:		
Beginning balance	85,528	72,573
Ending balance	$ 34,463	$ 57,303

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE SIX MONTHS ENDED DECEMBER 31, 2021 AND 2020 (IN THOUSANDS - UNAUDITED)

	2021	2020
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ (13,359)	$ 42,113
Other nonoperating income	242	120
Depreciation and amortization	72,804	60,098
Financing costs net of amortization of bond discount and refunding charge on defeasance of debt	(390)	(316)
Changes in operating assets and liabilities:		
Receivable from participants	7,385	(3,064)
Fuel inventories	24,870	5,673
Materials and supplies	(1,266)	(355)
Other current assets	(3,654)	(4,494)
Prepaid/accrued personnel services contract costs	-	-
Other liabilities	-	15,682
Accounts payable and accrued liabilities	(23,007)	(26,076)
Accrued credit to participants	5,909	25,136
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 69,534	$ 114,517

(Concluded)

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APPENDIX E

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

The information contained in this Appendix has been furnished to Intermountain Power Agency (the "Agency") by the Department of Water and Power of The City of Los Angeles (the "Department"). This Appendix presents dated information and neither the Agency nor the Department makes any representations regarding the accuracy of the information subsequent to the specified dates. Except as expressly provided, capitalized terms have the meanings set forth in the document to which this Appendix is attached.

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

General

The Department is the largest municipal utility in the United States and is a proprietary department of 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 4.0 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 the Charter adopted in 2000. The operations and finances of the Water System are separate from those of the Power System.

Charter Provisions

Pursuant to the Charter, 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 or a waiver of such period is granted by City Council. During those five City Council meetings (unless the waiver of such period has been granted), 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. 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:

CYNTHIA MCCLAIN-HILL, *President*. Ms. McClain-Hill was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on August 15, 2018. She was elected President of the Board on July 28, 2020 and was re-elected President of the Board on July 20, 2021. Ms. McClain-Hill is an attorney, co-founder, and managing director of the Los Angeles-based Strategic Counsel PLC, specializing in managing complex legal matters, strategizing public policy, advocacy, and communications. She previously served on the Los Angeles Board of Police Commissioners, the California Coastal Commission, the California Fair Political Practices Commission, the CalEPA Environmental Justice Advisory Working Group, the Community Redevelopment Agency for the City of Los Angeles, the Los Angeles Small and Local Business Advisory Commission and as president of the Los Angeles Chapter of the National Association of Women Business Owners. Ms. McClain-Hill holds a law degree and a bachelor's degree from the University of California at Los Angeles.

SUSANA REYES, *Vice President*. Ms. Reyes was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on June 5, 2019. She was elected Vice President of the Board on July 28, 2020, and was re-elected Vice President of the Board on July 20, 2021. She is the founder and CEO of AgilEngines LLC, an advocacy and consulting firm focusing on community outreach and civic engagement strategies. Ms. Reyes was the first Director of Low-Income Customer Access at the Department. Previously, she also served as a Senior Sustainability Analyst in the Office of L.A. Mayor Eric Garcetti and helped oversee the implementation of the first Sustainable City Plan. Ms. Reyes also served as Manager of the City's Facilities Recycling Program and as a Human Resources Director at the Department where she oversaw health and wellness programs, training and leadership development, and the Workers Compensation Program. She graduated magna cum laude from Saint Paul College with a degree in communications and pursued a Civic Engagement Leadership and Management certification from the UCLA Anderson School of Management, a Government Purchasing and Contract Administration credential from the George Washington University, and was a Certified Professional in Learning and Performance.

JILL BANKS BARAD-HOPKINS, *Commissioner*. Ms. Barad-Hopkins was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on September 11, 2013. Ms. Barad-Hopkins was re-confirmed to the Board on June 29, 2018. She owns Jill Barad & Associates, a political consulting, public relations and government affairs firm. Ms. Barad-Hopkins 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-Hopkins 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.

NICOLE NEEMAN BRADY, *Commissioner*. Ms. Neeman Brady was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on November 8, 2019. Ms. Neeman Brady was reappointed to the Board and confirmed on June 22, 2021. Ms. Neeman Brady has over eleven years of experience in energy, water, and agriculture management, and she currently serves as the Chief Operating Officer and Principal of the Renewable Resources Group, where she directs investments and develops opportunities. She also sits on the board of directors for the Library Foundation of Los Angeles. Prior to joining the Renewable Resources Group, Ms. Neeman Brady was President and Founder of Edison Water Resources, a subsidiary of Edison International, where she developed water treatment and recycling strategies. Ms. Neeman Brady also served in several leadership roles at the Southern California Edison Company ("Edison"), including the role of Director of Energy Procurement. Ms. Neeman Brady holds dual

Bachelor of Arts degrees, with honors, in architecture and economics from Brown University and a Master of Business Administration degree, with distinction, from Harvard Business School.

MIA LEHRER, *Commissioner*. Ms. Lehrer was appointed to the Board by Mayor Eric Garcetti and confirmed by the City Council on October 21, 2020. Ms. Lehrer is president and founder of Studio-MLA, a landscape architecture, urban design, and planning practice dedicated to advocacy by design with a vision to improve quality of life through landscape. She has served as an advisor to numerous public agencies, including the United States Fine Arts Commission under President Barack Obama, the Los Angeles Cultural Heritage Commission, and the Los Angeles Zoning Advisory Committee. The scope of her concerns is vast—from the master planning of cities to the design of intimate plazas and gardens—with a particular emphasis on progressive landscape design, resilient and people-friendly public places, urban waterways, and catalyzing work for a climate-appropriate future. Ms. Lehrer was a member of the team that delivered the Los Angeles River Revitalization Master Plan and the 2020 Upper Los Angeles River and Tributaries Master Plan. She also serves on the board for the Southern California Development Forum and in 2010 she was elevated to Fellow of the American Society of Landscape Architects. Ms. Lehrer holds a Bachelor of Arts degree from Tufts University and Master of Landscape Architecture degree from the Harvard University Graduate School of Design.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. The management structure of the Department consists of three functional senior executive positions: Senior Assistant General Manager of Corporate Services, Chief Sustainability Officer and Senior Assistant General Manager of External and Regulatory Affairs, and Chief Financial Officer. The Department's financial affairs are supervised by the Department's Chief Financial Officer. The Power System is directed by the Senior Assistant General Managers of the Power System. 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, Mr. Martin L. Adams, and other members of the senior management team for the Power System:

MARTIN L. ADAMS, *General Manager and Chief Engineer*. Mr. Adams was named Interim General Manager of the Department in July 2019 and confirmed as the General Manager and Chief Engineer by the City Council in September 2019. Prior to his appointment as General Manager, Mr. Adams served as the Chief Operating Officer of the Department since September 2016. In that capacity, he oversaw the Water System and Power System, along with other support organizations within the Department. Mr. Adams has more than 35 years of experience at the Department, where he started as an entry level engineer in the Water System, eventually leading the Water System as its Senior Assistant General Manager. During the course of his career, Mr. Adams worked throughout the Water System and was directly involved with the planning and implementation of major changes to water storage, conveyance, and treatment facilities to meet new water quality regulations. He has spent almost half of his career in system operations, including ten years as the Director of Water Operations in charge of the day-to-day operation and maintenance of the Los Angeles water delivery system, including the Los Angeles Aqueduct and other supply sources, pump stations, reservoirs, water treatment, and management of Water System properties. Mr. Adams received his Bachelor of Science degree in civil engineering from Loyola Marymount University in Los Angeles.

ANDREW C. KENDALL, *Senior Assistant General Manager of Corporate Services*. Mr. Kendall was named Senior Assistant General Manager of Corporate Services in November 2021. In this role, Mr. Kendall serves as the General Manager's representative for labor negotiations, and is working with the Office of Diversity, Equity, and Inclusion in restructuring the electrical crafts recruitment, hiring, and apprentice program, as well as the transition of the Utility Pre-Craft Trainee program from Power

Construction and Maintenance to the Office of Diversity, Equity, and Inclusion. Prior to this position, Mr. Kendall served as the Senior Assistant General Manager of the Power System – Construction, Maintenance and Operations since July 2015 and prior to that he served as the Senior Assistant General Manager Director for the Department's Power Transmission and Distribution Division since December 2014. Mr. Kendall has spent over 37 years working with the Department, including nearly 24 years of experience in supervisory and managerial positions coordinating the work of employees engaged in the construction, maintenance, and emergency repair of the Power System. He was appointed to Electric Distribution Mechanic Supervisor in 1996, Transmission and Distribution District Supervisor in 2000, and Electrical Service Manager in 2012. Mr. Kendall holds a bachelor's degree in business management from the University of Phoenix.

NANCY H. SUTLEY, *Chief Sustainability Officer and Senior Assistant General Manager of External and Regulatory Affairs*. Ms. Sutley was named Chief Sustainability Officer in 2014 and assumed the role of Senior Assistant General Manager of External and Regulatory Affairs in October 2019. Prior to joining the Department, Ms. Sutley served as Chair of the White House Council on Environmental Quality. Under her leadership, the Council played a central role in shepherding the Obama Administration's signature environmental projects and was one of the chief architects of President Obama's 2013 Climate Action Plan. Ms. Sutley has an extensive background in public service that includes posts as Deputy Mayor for Energy and Environment for the City of Los Angeles, Board Member of the Metropolitan Water District, Member of the California State Water Resources Control Board ("SWRCB"), Energy Advisor for California Governor Gray Davis, Deputy Secretary for Policy and Intergovernmental Relations at the California Environmental Protection Agency, and Senior Policy Advisor for the United States Environmental Protection Agency during the Clinton Administration. Ms. Sutley holds a bachelor's degree from Cornell University and a Master of Public Policy degree from Harvard University.

BRIAN J. WILBUR, *Senior Assistant General Manager of the Power System – Construction, Maintenance and Operations*. Mr. Wilbur assumed his current position as Senior Assistant General Manager of the Power System – Construction, Maintenance and Operations in November 2021. Mr. Wilbur has over 34 years of experience at the Department in construction, maintenance, and operations within the Power System. Mr. Wilbur began his career at the Department in 1987 as an Electrical Craft Helper and climbed the ranks in the Lineman series as an Apprentice Lineman, an Electric Distribution Mechanic, an Electric Distribution Mechanic Supervisor, an Overhead Distribution Design Pole Spotter, and as a Safety Supervisor. In July 2012 he was elevated to the management team as a Transmission and Distribution District Superintendent "B" for Central and West Los Angeles and as a Transmission and Distribution District Superintendent "A" for Central District and Safety. Mr. Wilbur was promoted to an Electric Service Manager overseeing Power System Safety and Training, the Assistant Director of Power New Business Development & Technology Applications Division in May 2018, and then as the Director of the Power Transmission and Distribution Division in October of 2019.

REIKO A. KERR, *Senior Assistant General Manager of the Power System – Engineering, Planning and Technical Services*. Ms. Kerr assumed the position of Senior Assistant General Manager of the Power System – Engineering, Planning and Technical Services in February 2017. Ms. Kerr previously served as the Assistant General Manager of the Power System – Strategic Policy, a position she held since November 2016. Prior to joining the Department, she served in a number of positions at Riverside Public Utilities, including as the Assistant General Manager of Resources and the Assistant General Manager of Finance and Administration, Finance & Rates Manager, and Energy Risk Manager. Ms. Kerr has spent over 18 years working in the public utility industry, all in managerial positions. Prior to working in the utility industry, Ms. Kerr spent seven years working in the public accounting and finance field. Ms. Kerr has served on committees of the American Public Power Association, Southern California Public Power Authority ("SCPPA"), Large Public Power Council, Western Electricity Coordinating Council, and CMUA and is a founding member and current board member of the Association of Women in Water, Energy and

Environment. Ms. Kerr holds a bachelor's degree in business administration from California State University at San Bernardino and is a certified public accountant in the State.

ANN M. SANTILLI, *Chief Financial Officer*. Ms. Santilli was named Chief Financial Officer of the Department in May 2019. She had served as Interim Chief Financial Officer of the Department since March 2018. Prior to her appointment as Interim Chief Financial Officer, Ms. Santilli served as Assistant Chief Financial Officer and Controller of the Department from 2012 through February 2018 and previously held the role of Interim Chief Financial Officer of the Department from October 2010 through January 2012. Prior to her first service 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 33 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.

KATHY M. FONG, *Assistant Chief Financial Officer and Controller*. Ms. Fong was named Assistant Chief Financial Officer and Controller of the Department in March 2020 after serving as the Acting Assistant Chief Financial Officer and Controller of the Department since March 2018. Ms. Fong previously served as Assistant Controller – Financial Reporting of the Department from August 2014 through February 2018 and held the role of Manager of Financial Reporting of the Department from June 2008 through July 2014. Prior to being appointed as the Manager of Financial Reporting in 2008, Ms. Fong served as the Assistant to the Manager of the Budget Office since 2002. Ms. Fong has over 31 years of accounting and budgeting experience. Ms. Fong holds a bachelor's degree in business administration with an option in accounting from California State University at Los Angeles and is a certified public accountant in the State and a certified management accountant.

PETER HUYNH, *Assistant Chief Financial Officer and Treasurer; Assistant Auditor*. Mr. Huynh was named Assistant Chief Financial Officer and Treasurer of the Department in October 2020 and Assistant Auditor of the Department in February 2021. Prior to his appointment as Assistant Chief Financial Officer and Treasurer, Mr. Huynh served as the Assistant Director of Finance and Risk Control Division of the Department since July 2006. He has over 31 years of financial management experience in debt management, risk control, financial planning, accounting, and auditing. Mr. Huynh holds a bachelor's degree in art and a certificate in accountancy from the California State University of Los Angeles. He also has a master's degree in business administration from Pepperdine University. Mr. Huynh is a certified public accountant in the State, a certified management accountant, and a chartered global management accountant.

Employees

As of January 31, 2022, the Department assigned approximately 5,236 Department employees to the Power System on a full time basis. Approximately 3,329 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 14 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") which extend through September 30, 2022. IBEW represents more than 90% of the Department's employees through ten bargaining units. The current memoranda of understanding were approved by the City Council on June 28, 2017. In 2014, through prior negotiations, the Department made changes to the pension program that 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 for employees who transfer between the systems. The Coalition of L.A. City Unions, whose members are not employed at the Department, has challenged the ending of the reciprocity agreement. The Department and City are defending the challenge against the decision to end the reciprocity agreement.

The Department's memorandum of understanding with the Load Dispatchers Association expired on December 31, 2020. The Department's memoranda of understanding with the Management Employees Association and the Association of Confidential Employees expired on December 31, 2021. The Department is currently in negotiations with the Load Dispatchers Association and Management Employees Association. All employment terms of each of the current memorandum of understanding with these associations continue until a successor contract is executed. The Department's memorandum of understanding with the Service Employees International Union, Security Unit ("SEIU"), expires on September 30, 2022. Since the advent of collective bargaining in 1974, work stoppages have been rare, occurring in 1974, 1981 and 1993.

Retirement and Other Benefits

Retirement, Retiree Medical, 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 is a retirement system of employee benefits and includes the Water and Power Employees' Retirement Fund (the "Retirement Plan"), which is more fully described in "Note (13) Retirement Plan" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Retirement Plan are shared by the Power System and the Water System, with the Power System being responsible for approximately 67% of Retirement Plan costs. Since Fiscal Year 2014-15, the assumed rate of investment return on the Retirement Plan's assets has been incrementally decreased from 7.75% to 7.00%. Most recently, effective July 1, 2019, the Retirement Board lowered the assumed rate of return from 7.25% to 7.00%. This decrease has contributed to an increase of the Department's required contributions to the Retirement Plan, including the Power System's share. The budgeted contributions described below for the Fiscal Years ending June 30, 2020 and June 30, 2021 take into account this change in the discount rate. Investment return assumptions are determined through the Retirement Plan's Experience Study, the next of which is scheduled in the summer of 2022.

As more fully described in Note 13(d), the Power System made contributions to the Retirement Plan of approximately $258.6 million in Fiscal Year 2020-21 (as part of a total Department contribution of approximately $384.2 million), and the Power System made contributions to the Retirement Plan of approximately $288.6 million in Fiscal Year 2019-20 (as part of a total Department contribution of

approximately $428.6 million). For the Fiscal Year ending June 30, 2022, the Department has budgeted a contribution of approximately $296.4 million from the Power Revenue Fund to the Retirement Plan (as part of a total Department contribution of approximately $435.9 million). The Department also has made, and will continue to make in the future, contributions to the Plan from the Water Revenue Fund.

The Department follows the provisions of Governmental Accounting Standards Board ("GASB") Statement No. 68, *Accounting and Financial Reporting for Pension Plans – an amendment of GASB Statement No. 27* ("GASB No. 68"). GASB No. 68 requires employers with pension liabilities to disclose the net pension liability along with deferred inflows and outflows of resources related to the pension liability. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 68 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" of the Department's Power System Financial Statements. Specifically, see Note 6(f) for a discussion of the Power System's establishment of the regulatory asset discussed above.

According to the latest actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on October 7, 2021, as of July 1, 2021, the market value of the assets in the Retirement Plan was approximately $16.7 billion, which results in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $1.7 billion; the actuarial value of the assets in the Retirement Plan as of such date was approximately $14.9 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $119.6 million. As of July 1, 2021, the Retirement Plan had unrecognized gains of approximately $1.8 billion. The Retirement 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 net deferred gains for the year ended June 30, 2021 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2021-22 would decrease from approximately 26.0% of total Department covered payroll to 10.7% of total Department covered payroll. Additionally, if the net deferred gains in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2021 would increase from approximately 99.2% to 111.1%.

According to the actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on October 19, 2020, as of July 1, 2020, the market value of the assets in the Retirement Plan was approximately $13.4 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $1.1 billion; the actuarial value of the assets in the Retirement Plan as of such date was approximately $13.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $879.2 million. As of July 1, 2020, the Retirement Plan had unrecognized losses of approximately $232 million. The Retirement 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 net deferred losses for the year ended June 30, 2020 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2020-21 would increase from approximately 33.6% of total Department covered payroll to 35.6% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2020 would decrease from approximately 93.9% to 92.3%.

Contribution requirements for the Fiscal Year ending June 30, 2023 are set based on the asset values as of June 30, 2022, and it is not possible to predict where the market will be at that time. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities and future pension costs. However, the Retirement Plan uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retirement benefits, requires the employee to contribute a higher percentage of pay to the Retirement Plan, and ends the reciprocity agreement with the City's retirement plan. See "Employees" above with respect to the Coalition of L.A. City Unions' challenge to the ending of the reciprocity agreement. According to a study of the proposed benefits of Tier 2, which was completed by The Segal Company on October 24, 2013, the estimated amount of contribution required to fund the benefit allocated to the current year of service (the "Normal Cost"), as a percentage of payroll, was 5.61% for Tier 2 (as compared to 16.35% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $877 million over 30 years (based on the 7.75% assumed rate of investment return on the Retirement Plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on October 7, 2021, the estimated contribution for Fiscal Year 2021-22 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, will be 8.78% for Tier 2 (as compared to 18.87% for Tier 1). As of the July 1, 2021 actuarial valuation report, 44% of active Department members were covered under Tier 2.

Other Postemployment Benefits ("OPEB"). The Department provides certain healthcare benefits (the **"**Healthcare Benefits**"**) and death benefits to active and retired employees and their dependents. These OPEB Benefits are more particularly described in **"**Note (14) Other Postemployment Benefits Plans**"** and the **"**Required Supplementary Information**"** of the Department**'**s Power System Financial Statements.

The costs of the Healthcare Benefits are shared by the Water System and the Power System, with the Power System historically being responsible for approximately 67% of the costs of the Healthcare Benefits. As more fully described in Note (14), the Power System paid Healthcare Benefits of approximately $71.1 million in Fiscal Year 2020-21 (as part of a total Department contribution of approximately $106.0 million) and the Power System paid Healthcare Benefits of approximately $70.0 million in Fiscal Year 2019-20 (as part of a total Department contribution of approximately $105.9 million). For the Fiscal Year ending June 30, 2022, the Department has budgeted approximately $84.6 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $124.4 million). The Department also has paid, and will continue to pay in the future, Healthcare Benefits from the Water Revenue Fund, for the Water System's Healthcare Benefits costs.

According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on December 7, 2021, as of June 30, 2021, the market value of the assets of the Healthcare Benefits was approximately $2.918 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $349 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $2.599 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $30 million. As of June 30, 2021, the Healthcare Benefits had unrecognized investment return of approximately $319.2 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.

The ratio of the actuarial value of assets to actuarial accrued liabilities increased from 93.90% as of Fiscal Year ending June 30, 2020 to 101.15% as of Fiscal Year ending June 30, 2021. On a market value of assets basis, the funded ratio increased from 92.51% to 113.58%. The unfunded actuarial accrued liability decreased from $151.8 million to a surplus of $29.6 million.

According to the actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on December 2, 2020, as of June 30, 2020, the market value of the assets of the Healthcare Benefits was approximately $2.304 billion, which would result in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $187 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $2.338 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $152 million. As of June 30, 2020, the Healthcare Benefits had unrecognized investment losses of approximately $34.7 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.

Contribution requirements for the Fiscal Year ending June 30, 2023 are set based on the asset values as of June 30, 2022, and it is not possible to predict where the market will be at that time. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities for Healthcare Benefits and future contribution requirements. However, the Healthcare Benefits uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

For a schedule that provides information about the Department's overall progress made in accumulating sufficient assets to pay Healthcare Benefits when due, prior to allocations to the Power System and the Water System, see the "Required Supplementary Information" of the Department's Power System Financial Statements.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retiree healthcare benefits. According to a study of the proposed OPEB for Tier 2 employees of the Department, which was completed by The Segal Company on November 8, 2013, the estimated Normal Cost, as a percentage of payroll, was 2.63% for Tier 2 (as compared to 4.33% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $136.5 million over 30 years (based on the 7.75% assumed rate of investment return on the OPEB plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on December 7, 2021, for Fiscal Year, 2021-22, the Normal Cost, as a percentage of payroll, will be 3.79% for Tier 2 (as compared to 4.17% for Tier 1).

Effective July 1, 2017, the Department follows the provisions of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, an amendment of GASB Statement No. 45 ("GASB No. 75"). GASB No. 75 requires employers with other postemployment liabilities to disclose the net postemployment liability along with deferred inflows and outflows of resources related to the other postemployment liability. The Department adopted the provisions of GASB No. 75 beginning for the Fiscal Year ended June 30, 2018. Accordingly, the cumulative effect of the impact on net position as of July 1, 2017 was negative $661.2 million. As of June 30, 2021, the Power System has a

net OPEB liability of $191.4 million comprised of $126.2 million of retiree medical and $65.2 million in death benefits. As of June 30, 2020, the Power System has a net OPEB liability of $388.7 million comprised of $316.6 million of retiree medical and $72.1 million in death benefits. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 75 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" in the Department's Power System Financial Statements. Specifically, see Note 6(g) for a discussion of the Power System's establishment of the regulatory asset discussed above.

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 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 Board has most recently approved transfers totaling $225,015,000 to the City during the Fiscal Year ending June 30, 2022. The transfers are expected to be made in the last quarter of Fiscal Year 2021-22.

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

POWER TRANSFERS
FOR FISCAL YEARS ENDED JUNE 30, 2017 – 2021
(in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2017	$264,427
2018	241,848
2019	232,557
2020	229,913
2021	218,355

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

In accordance with the State court settlement described under "LITIGATION – Litigation Regarding Power Transfer," the City has agreed not to include any funds in the Power Transfer that the Department collects pursuant to the Electric Rates established under the Incremental Electric Rate Ordinance, which was adopted in 2016. However, the Power Transfer will continue to include surplus revenue generated from Electric Rates established under the Rate Ordinance adopted in 2008. Starting in Fiscal Year 2017-18, the Power Transfer is approximately 1.01 cents for every kWh sold to retail electric customers.

Insurance

The Department's insurance program currently consists of a combination of commercial insurance policies and self-insurance. All general liability claims within the self-insured retention of $3 million are covered under the Department's self-insurance program and the Department carries commercial excess general liability insurance above its self-insured retention. There are two separate towers of insurance. The first is for non-wildfire losses and has a primary layer of $35 million, which includes 30% of co-insurance, supported by additional layers of commercial liability insurance. The total limit available for non-wildfire losses is $160 million. There is a second tower of insurance that is solely for wildfire losses. The total limit available for wildfire losses is $243.5 million. The Department has a $38 million self-insured retention and above the initial retention layer, the Department has procured an additional $125.5 million of commercial wildfire insurance. To complement its overall wildfire insurance program, the Department has further provided for $80 million of coverage through Catastrophe Bonds (each, a "CAT Bond"). The first bond type consists of a $50 million parametric wildfire CAT Bond that has an attachment point of $75 million and is intended to cover a portion of any large claim in excess of $75 million. The second bond is a $30 million indemnity wildfire CAT Bond that sits above the commercial insurance tower and is intended to cover a portion of any claim that might exceed the self-insurance and commercial insurance coverage. The CAT Bonds are multi-year issuances and pay out based on a catastrophic fire event that occurs within the three (3) year period of each specific bond. The CAT Bonds allow the Department to obtain additional wildfire coverage capacity outside of a commercial insurance policy, but, unlike commercial insurance, the Department achieves a premium cost that is fixed and known for the three-year period of the bonds. For discussion regarding liability issues as they relate to wildfire losses, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

Going forward, the Department will continue to consider any available coverage options in the market in order to ensure that the Department is adequately protected against catastrophic liability events and wildfires. In addition to the excess general liability insurance programs and the CAT Bond issuances, the Department continues to maintain a bona fide program of self-insurance as well. As of January 31, 2022, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $212.475 million. The Power Revenue self-insurance fund is specific to the Power Division and is primarily designed to cover a large catastrophic event that could affect the Power Division operations (e.g. liability for a large wildfire.) The Department annually reviews the amount retained for self-insurance and may adjust such amount if it deems such adjustment appropriate.

The Department has purchased a primary cyber insurance policy in the amount of $50 million, with a $1 million self-insured retention. This insurance policy covers certain types of cyber incidents and provides reimbursement coverage for costs to respond to data privacy or security incidents and for expenses incurred in connection with the investigation, prevention, and resolution of any cyber threat.

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 loss limit of $500 million for all claims in a single policy year. The all-risk property insurance has a deductible of $5 million. The Department recently secured earthquake coverage and sudden and accidental pollution coverage as part of its all-risk property insurance program.

The Department's physical plant coverage does not provide coverage in certain events including terrorism or war. However, the Department has purchased a Terrorism Limits and Terrorism Risk Insurance Extension Act of 2005 ("TRIEA") Endorsement (the "Endorsement") to its excess general liability coverage under which coverage is extended to cover losses resulting from certain acts certified by the Secretary of

the U.S. Department of the Treasury to be an act of terrorism, as defined in TRIEA. Currently, from 2002 through December 31, 2027, the Endorsement limits insurers liability for losses resulting from certified acts of terrorism when the amount of such losses in any one calendar year exceeds $100 billion. If the aggregate insured losses for all insurers exceed $100 billion, the Department's coverage may be reduced.

As a participant in the Palo Verde Nuclear Generating Station ("PVNGS") and associated transmission systems, the Department is an additional named 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 the facility.

The Department, as the operating agent for the Intermountain Power Project ("IPP"), the Mead-Adelanto Transmission Project, the Pacific DC Intertie and in connection with its relationships with other entities and agencies, includes other entities or agencies as additional named 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. Insurance limits maintained by the Department are subject to change depending on market conditions and assessments by the Department as to risk exposure. The utilization of commercial insurance along with alternative risk options such as CAT Bonds allows the Department to strengthen its overall risk management program as well as provide flexibility in setting and adjusting its self-insurance retention limits as part of the continual review of the Department's insurance budget.

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 with an independent trustee ("Trust Funds") more fully described in "Note (7) Cash, Cash Equivalents, and Investments" of the Department's Power System Financial Statements ("Note 7"), are not included in the City's investment pool program. The Department manages the investment of the Trust Funds in which approximately $660 million (investments at fair market value) was on deposit as of January 31, 2022. 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). Such funds consist of debt reduction trust funds, the nuclear decommissioning trust funds, the natural gas trust fund, the California Independent System Operating Markets trust fund, and the hazardous waste treatment storage and disposal trust fund. These trust funds are being held by U.S. Bank Trust Company, National Association as trustee/custodian. Amounts in the debt reduction trust fund are to be applied at the discretion of the Chief Financial Officer, 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, 2022, the debt reduction trust fund had a balance of approximately $489.3 million (investments at fair market value as of such date).

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 its 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 FUNDS INVESTMENTS
ASSETS AS OF JANUARY 31, 2022
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Government Securities	$ 46,710
U. S. Sponsored Agency Issues	198,205
Supranational discount notes	43,263
Medium term corporate notes	103,241
Municipal obligations	114,525
California state bonds	27,951
Other state bonds	57,987
Commercial paper	1,995
Certificates of deposit	34,938
Bankers acceptances	0
Money market funds	31,303
Total	$660,120*

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. 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. 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.

The Board has adopted an Environmental Credit and Renewable Energy Credit Policy to establish a risk management program that is designed to manage the Department's exposure to risks resulting from purchases and sales of emissions credits or allowances and other credits available for the purpose of compliance with environmental laws, rules, and regulations. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types, and establishes internal controls surrounding credit risk management activity.

The Board has adopted a Dodd-Frank Act Compliance Policy to ensure the Department complies with applicable provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and commodity futures trading commission requirements.

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, 2022, the Power System had approximately $2.0 billion of unrestricted cash and approximately $614 million of restricted cash on deposit with the City. This amount is in addition to what is on hand in the Trust Funds, see "—Department's Trust Funds Investment Policy" above. 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. Funds invested by the Power System in the pooled investment program are available for withdrawal within five business days without penalties. In addition, 19% of the pool, as of June 30, 2021, had maturities less than one month and 34% of the pool, as of June 30, 2021, had maturities of one year or less.

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CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2021
(Dollars in Thousands)
(Unaudited)

	Fair Market Value	Percent of Total	Power System Share
U.S. Treasury Notes	$ 7,896,966	60.19%	$872,095
U.S. Agencies Securities	535,039	4.08	59,087
Medium-Term Notes	1,236,167	9.42	136,515
Mutual Fund	2,468	0.02	273
Commercial Paper	1,489,447	11.35	164,486
Negotiable Certificate of Deposit	668,256	5.09	73,798
Municipal Bonds	20,330	0.15	2,245
Asset-Backed Securities	54,959	0.42	6,069
Supranational Coupons	101,746	0.78	11,236
Short-Term Investment Funds	1,020,887	7.78	112,741
Securities Lending Cash Collateral:			
Repurchase Agreement	93,390	0.72	10,313
Total General and Special Pools	**$13,119,655**	**100.00%**	**$1,448,858**

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.
Note: Fair Market Value as of June 30, 2021.

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.

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 or 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 required to be 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.

For more information about the investments in the City's Office of Finance pool, see Note (7).

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 completed interim rate review of the last rate action for Fiscal Year 2015-16 through Fiscal Year 2019-20 resulted in planned annual system average Electric Rate increase adjustments. The average yearly increase during the five-year period was approximately 4.5% for low-energy users, approximately 4.0% for midrange users, and approximately 5.5% for top tier users, reflected in increased actual pass-through cost adjustments and decreased Base Rate revenue targets. For a discussion of recent rate actions taken at the recommendation of the Office of Public Accountability, see "- *Office of Public Accountability*" below.

The rate increase over these five Fiscal Years is reflected in the Incremental Electric Rate Ordinance and as a result, effective April 15, 2016, the Department's retail electric revenue requirement has been funded from the Rate Ordinance adopted in 2008 and the Incremental Electric Rate Ordinance through the following major components:

(a) Under the Rate Ordinance adopted in 2008:

(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, in addition to including the Power Access Charge, which is a consumption-based tiered charge applied to residential non-Time-of-Use Residential Rate customers used to recover basic infrastructure costs for providing access to the power grid;

(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, IRCA, 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.

On the recommendation of the Office of Public Accountability (the "OPA"), the Board decreased the Base Rate revenue targets for Fiscal Year 2018-19 and Fiscal Year 2019-20 by 2% each. The OPA further recommended, and the Department supports the recommendation, to use four-year rate action cycles, rather than replicate the recent five-year rate action cycle. The Department is currently reviewing the timing of the next rate action and expects to have a schedule for proposing the next rate action to the Board by the end of Fiscal Year 2021-22.

Proposition 26. In 2010, California voters approved Proposition 26 (**"**Proposition 26**"**), an initiative measure amending Article XIII C of the State Constitution to add a new definition of **"**tax.**"** Each such tax cannot be imposed, extended, or increased by a local government without voter approval. Article XIII C of the State Constitution, as amended by Proposition 26, defines **"**tax**"** to include any levy, charge, or exaction imposed by a local government, except, among other things, (a) charges imposed for benefits conferred, privileges granted, or services or products provided, to the payor (and not to those not charged) that do not exceed the reasonable costs to the local government of conferring, granting or providing such benefit, privilege, service, or product, and (b) property-related fees imposed in accordance with the provisions of Article XIII D of the State Constitution. The Department believes that the Electric Rates and charges do not constitute taxes as defined in Article XIII C of the State Constitution. See **"**LITIGATION **–** Litigation Regarding Power Transfer.**"**

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 operating cash target of the equivalent of 170 days of operating expenses, (ii) maintain full obligation coverage of at least 1.7 times, and (iii) maintain a debt-to-capitalization ratio of less than 68%. These criteria are subject to reviews and adjustments from time to time by the Board with advice from the Department**'**s financial advisors and were most recently revised on May 26, 2020.

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. The review by the City's Neighborhood Councils of the rate action involving the Incremental Electric Rate Ordinance for Fiscal Year 2015-16 through Fiscal-Year 2019-20 was completed prior to its adoption by City Council and effectiveness.

Office of Public Accountability. Section 683 of the Charter establishes 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 the Electric Rates and water rates. The role of the OPA is advisory rather than as 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 April 15, 2016, 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. As a result of the rate action involving the Incremental Electric Rate Ordinance for Fiscal Year 2015-16 through Fiscal-Year 2019-20, the Department is required to provide semi-annual written reports regarding certain Board-established metrics to the Board and the OPA. Dr. Pickel was reappointed as Executive Director of the OPA on December 5, 2018 for a five-year term.

Rate Regulation

While changes in the retail Electric Rate ordinances 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 the Federal Energy Regulatory Commission ("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.

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 ("POUs").

Although its retail Electric Rates are not subject to approval by any state or 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 electric utilities when FERC determines that the QFs have non-discriminatory access to wholesale power markets with certain characteristics. The Department has neither applied for nor been relieved of its mandatory purchase obligation. 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 electric transmission access to others at cost-based rates. FERC also has licensing authority over various

hydroelectric facilities owned and operated by the Department and regulates the reliability and security of the nation's bulk power system.

Furthermore, with, among other things, the consent of the Department, operational control of the transmission facilities owned or controlled by the Department may be transferred to the California statewide network administered by the California Independent System Operator Corporation ("Cal ISO"). See "THE POWER SYSTEM – Transmission and Distribution Facilities." In 2017, the Department updated its Open Access Transmission Tariff ("OATT"), which included revising the cost-of-service and rate design for the Department's wholesale transmission rates. In 2020, the Department updated its OATT to facilitate entry into Cal ISO's Western Energy Imbalance Market (the "EIM"). The April 2020 amendment to the Department's OATT focused predominantly on non-rate terms and conditions related to the EIM, to ensure that services under the OATT would continue to be provided in a comparable and not unduly discriminatory or preferential manner to all of the Department's OATT customers. The April 2020 amendment largely followed similar, prior OATT amendments of other utilities already participating in the EIM. For more information on the Department's entry into the Western EIM, see "THE POWER SYSTEM – Transmission and Distribution Facilities."

Billing and Collections

General. With some limited exceptions, 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, solid waste resources fee and State and local taxes). Payments are posted in the following order: overdue receivables, customer deposits, water charges, electric charges, State and local taxes, sewer service charges, solid waste resources fees and bulky item fees.

Billing System and Delinquencies. In September 2013, the Department launched a new customer information and billing system, designed and implemented by Pricewaterhouse Coopers LLP. Immediately following the launch of the new billing system, the Department experienced numerous billing issues in connection with the new system, including, but not limited to, (a) the inability to issue bills to customers, (b) the inability to issue accurate bills to customers, (c) an increase in estimated bills that were sent to customers where metering information was not available, and (d) the inability to generate multiple business reports, including financial reports reflecting the Department's accounts receivable. See "LITIGATION—Legal Actions Related to New Customer Information and Billing System."

Prior to the billing issues discussed above and based on annual historical experience of delinquencies, the Department historically has been unable to collect approximately 0.7% of the amounts billed to its customers. This amount may potentially increase in connection with the ongoing resolution of the billing issues noted above, as there has been a higher proportion of customer accounts receivable that were considered past due. In light of this and in response to the COVID-19 pandemic described below, the allowance for doubtful accounts has been increased to 2.0% of Power System sales since Fiscal Year 2020-21, creating an allowance of $245.6 million for the Fiscal Year ended June 30, 2021.

Power System accounts receivables (including utility user's tax) as of June 30, 2021 were $774.2 million compared to $582.6 million as of June 30, 2020. Of these amounts, $418.8 million (54.10% of total receivables) and $243.0 million (41.71% of total receivables) were 120 days or more past the payment due date as of June 30, 2021 and June 30, 2020, respectively. As of January 31, 2022, the Power System's allowance for doubtful accounts was $289.4 million and accounts receivable were $813.2 million (including utility user's tax). Of these amounts, $374.2 million (46.02% of total receivables) were 120 days or more past the payment due date. As of January 31, 2021, the Power System's allowance for doubtful accounts

was $228.4 million and accounts receivable were $775.6 million (including utility user's tax). Of these amounts, $364.1 million (46.94% of total receivables) were 120 days or more past the payment due date.

The new customer information and billing system is currently being used by the Department. The Department continues to work to improve the functionality of the system to meet the Department's original expectations for the new system.

COVID-19 Response. In response to the COVID-19 pandemic, the Department has not been shutting off power to customers if they are not able to pay their bills due to financial hardship. As a result, the Department has experienced an increase in the amount of bills that are 120 days or more past their payment due date. Ultimately, customers are still responsible to pay the billed amounts and the Department will work with customers by providing payment options. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – COVID-19 Pandemic."

The California Legislature established in the 2021-22 State Budget the California Arrearage Payment Program (CAPP) to provide financial assistance for California energy utility customers to help reduce past due energy bill balances during the COVID-19 pandemic. Administered by the Department of Community Services and Development (the "CSD"), CAPP dedicates approximately $994 million in federal American Rescue Plan Act funding to address Californian's energy debts, of which approximately $299 million is allocated for financial assistance to customers of POUs and electrical cooperatives. CAPP implementation is divided into four distinct phases. During phase one, the total residential energy arrearages are quantified through a survey of energy utilities. During phase two, applications are submitted for assistance. During phase three, CAPP benefits are applied directly to eligible residential and commercial customer accounts. During phase four, required reports are submitted to the CSD to confirm the outcome of delivered CAPP benefits. The Department submitted its survey on September 3, 2021 including a funding request of approximately $203 million for residential arrearages and approximately $109 million for commercial arrearages. The Department received $202.8 million of funding of which $201.5 million have been credited towards residential arrearages. As authorized by the CSD, the Department plans to credit the remaining $1.3 million towards commercial arrearages in March of 2022.

Write-Off Procedures. Uncollectible accounts are recoverable by the Department by passing on such "bad debts" to the ratepayers via pass-through adjustment factors. Due to hot weather in the summer and associated higher bills and the Department's bimonthly billing process, accounts receivable balances generally increase in the late summer and autumn and generally decrease in the winter and spring. These accounts receivable balances include inactive accounts. Inactive accounts that are included in accounts receivable that cannot be linked to an active account will be written off as uncollectible.

As part of the implementation of new write-off procedures beginning in the fourth quarter of Fiscal Year 2018-19, the Department reduced accounts receivable and the allowance for doubtful accounts by $19.2 million representing closed accounts that were uncollectible in June 2021, and additional reductions to these accounts are anticipated.

Customer Bill of Rights. In January 2017, the Board adopted a "Customer Bill of Rights" which was developed by the Department in consultation with Mayor Eric Garcetti and is designed to improve service for Department customers. On February 26, 2019, the Board extended the "Customer Bill of Rights" indefinitely.

THE POWER SYSTEM

General

The Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,734 megawatts ("MWs") and net dependable capacity of 8,101 MWs as of January 31, 2022, and properties with a net book value of approximately $12.74 billion as of January 31, 2022. The Power System's highest load registered 6,502 MWs on August 31, 2017. Based on the Department's June 2021 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2019-20 to Fiscal Year 2029-30 at a forecasted rate of approximately 1.66% 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 and battery electric vehicles. In the Power System's most recent resource plan, which was published in December 2017, significant energy efficiency measures are planned 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 the end of 2020, are anticipated to result in net overall energy consumption that increases by 0.04% per year over this period. The Department has achieved its energy efficiency goal for 2020 and is now focused on a tentative projection towards an additional 4,347 GWh of energy savings by 2035. 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, 2022) and energy mix (actual numbers for calendar year 2020) were approximately as follows:

DEPARTMENT GENERATION MIX PERCENTAGES

Resource Type	Capacity Percentage[1]	Energy Percentage[2]
Natural Gas	38%	27.9%
Large Hydro	17	5.4
Coal	11	16.0
Nuclear	4	14.0
Renewables	30	36.7
Storage	<1	–
Unspecified Sources of Energy[3]	–	0.1
Total	100%	100%

(1) Net Maximum Unit Capability as of October 31, 2021.
(2) Energy percentage is based on the Department's calendar year 2020 fuel mix submission as part of the 2020 Annual Power Content Label (APCL) to the California Energy Commission in September 2021.
(3) Unspecified sources of energy means electricity from transactions that are not traceable to specific generation sources.
Note: Totals may not equal sum of parts due to rounding.

The Department anticipates that its generation mix will change in response to statutory and regulatory developments. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY."

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 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, 2022.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of January 31, 2022, are summarized in the following table:

DEPARTMENT OWNED FACILITIES

Type of Fuel	Number of Facilities	Number of Units	Net Maximum Capacity (MWs)[1]	Net Dependable Capacity (MWs)[1]
Natural Gas	4[2]	29[2]	3,411	3,225
Large Hydro	1	7	1,265	1,265
Renewables	66	163[3]	417	277[4]
Storage	1	1	20	20
Subtotal	**72**	**200**	**5,113**	**4,787**
Less: Payable to the California Department of Water Resources	–	–	(120)[5]	(40)[5]
Total	**72**	**200**	**4,993**	**4,747**

Source: Department of Water and Power of the City of Los Angeles.
(1) Based on 2021 capacity ratings.
(2) Consists of the four Los Angeles Basin Stations (Haynes, Valley, Harbor and Scattergood) discussed and defined below. See *"—Once-Through-Cooling Units Phase-Out"* below for information regarding the future expected phase out of certain natural gas units.
(3) Includes 22 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 Department-built photovoltaic solar installations, the Pine Tree Wind Project and a local small hydro plant. Not included are the units that were upgraded at the Castaic Plant.
(4) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.
(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 3,411 MWs and a combined net dependable generating capacity of 3,225 MWs. Natural gas is used as fuel for the Los Angeles Basin Stations. Ultra-low-sulfur 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**."** The four Los Angeles Basin Stations are briefly described below.

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 1,614 MWs and a net dependable capacity of 1,551 MWs. The 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–plus–one configuration (and are counted by the Department as three generating units). In July 2013, the Department completed the replacement of two of the original units with six advanced simple-cycle gas turbine units. The Department expects to demolish

four Haynes Generating Station Units that were decommissioned between 2003 and 2013 to create a construction area for a future energy project. The demolition of the decommissioned Haynes Generating Station Units is not expected to impact the energy output of the Haynes Generating Station. Given the pandemic and contractual arrangement, certain options related to the scope of the project may be exercised and/or performed after final completion of the demolition project, which may delay the schedule into September 2022. The Department does not expect any additional or optional scope of the demolition project to impact the energy generation of the Haynes Generating Station. See **"**FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY **–** 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 combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). The net maximum plant capacity for the Valley Generating Station is 576 MWs. The total net dependable capacity for the Valley Generating Station is 530 MWs.

Valley Generating Station Gas Vent-Off. While conducting methane surveys across the State for the CEC in August 2020, the Jet Propulsion Laboratory (**"**JPL**"**) observed an increase with the methane vent-off over the Valley Generating Station reciprocating natural gas compressor area. This site was just one of over 1,100 identified methane sources in the State. The EPA had previously estimated that the emissions from compressors in the natural gas industry only accounted for approximately 24% of all methane emissions from the natural gas industry. After the Department was notified by JPL, the in-kind replacement of the compressor rod packing seals, which had begun to wear prematurely, was expedited. Although the replacement reduced the leakage by over 90%, efforts to obtain new design rod packing seals for the Valley Generating Station continued. These were already on order but the delivery was delayed due to the COVID-19 pandemic. The new design rod packing seals were installed in December 2020 and have been working as designed, with no measured or reported vent-off emissions from the compressors. Methane concentrations are currently being measured with methane analyzers installed on the property.

There were five Los Angeles Superior Court cases related to the referenced vent-off and operation of the Valley Generating Station. However, one of these cases, a class action lawsuit with a putative class of 30,000 individuals, was dismissed on December 27, 2021 as a result of motions filed by the Department. With the dismissal of the class action lawsuit, there are four remaining cases. These include *Pueblo y Salud, Inc, et. al. v. Los Angeles Department of Water and Power, et al.*, Los Angeles Superior Court case number 21STCV04346/20STCV48159, the lead case. As a result of the Department's motions referenced above, the Department's former General Manager and current General Manager were dismissed as defendants from this case. Additionally, punitive damages were removed, and the number of causes of action was reduced. Due to these motions, the Complaint in this case was amended on March 11, 2022. The amended Complaint contains 14 causes of action and 2,419 individual plaintiffs. The parties will be participating in a Status Conference with the court on April 28, 2022 where the Department anticipates instruction from the court regarding its responsive pleading deadline to the amended Complaint.

The other three cases allege the same nine causes of action and include one case filed on behalf of 14 individual plaintiffs (*Carly Jones, et al. v. Los Angeles Department of Water and Power, et al*., Los Angeles Superior Court case number 21STCV22541), one case filed on behalf of 15 individual plaintiffs (*Ricardo, et al. v. Reyes Los Angeles Department of Water and Power, et al*., Los Angeles Superior Court case number 21STCV21942) and one case filed on behalf of 10 individual plaintiffs (*Jonathan Atkins, et*

al. v. Los Angeles Department of Water and Power, et al., Los Angeles Superior Court case number 21STCV25022). The Department's responsive pleadings in these cases are stayed, pending court determinations regarding management of the multiple lawsuits. All four cases have been deemed related by the court and are assigned to the same judge. Aside from these cases, additional individual cases are possible, however, additional class action cases are not likely.

The Department's exposure for the Valley Generation Station, if there is liability, is not now known. The Department has notified carriers which may afford possible insurance coverage for the underlying incident, however, at the present time no insurance coverage nor the amount of coverage, if any, has been confirmed.

Harbor Generating Station. The Harbor Generating Station is located in Wilmington, California. The Harbor Generating Station is comprised of a combined-cycle unit, which consists of three generating units, and five additional peaking combustion turbines for a total of eight generating units. The Harbor Generating Station's net maximum capacity is 443 MWs with a net dependable capacity of 422 MWs. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – 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 two conventional steam boiler generating units, one combined-cycle generating unit, and two advanced simple-cycle gas turbines with a net maximum capacity of 778 MWs and a net dependable capacity of 759 MWs from natural gas. The Department expects to improve the site to maintain reliability of the Power System and to comply with the State's once-through-cooling requirements. Scattergood Generating Station Unit 3 was decommissioned in December 2015 and has been demolished to create the construction area for a future energy project. The decommissioning and demolition of Scattergood Generating Station Unit 3 does not significantly impact the energy output of the Scattergood Generating Station. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *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 Units Phase-Out. Generating units at the Los Angeles Basin Stations that currently utilize once-through-cooling have a total net maximum capacity of 1,661 MWs. In February 2019, Mayor Eric Garcetti announced that these units will be phased out and replaced with energy storage and clean energy alternative assets. The Department has initiated the City's planning efforts for replacing the capacity of the once-through cooling units as they retire by December 31, 2029. As part of these planning efforts, the Department issued a distributed energy resources request for proposals in September 2020 and is exploring the potential of distributed energy resources for replacing a portion of the capacity of the once-through-cooling units. Evaluation of these proposals began in May 2021 and is currently ongoing. The Department also presented its "Clean Grid LA Plan Update" to the Board on May 11, 2021, which details high level initiatives to address once-through cooling units phase-out and align with LA100 Study scenarios. The "Clean Grid LA Plan" and the LA100 Study will be incorporated into the Department's 2022 Power Strategic Long-Term Resource Plan (the "Strategic Long-Term Resource Plan") to formalize a roadmap for achieving 100% carbon free energy by 2035 for Board consideration. The Department anticipates the completion of the Strategic Long-Term Resource Plan by September 2022.

Other Department-Owned Generating Facilities. In addition to the Los Angeles Basin Stations, the Department is the sole owner of a number of other generating facilities. Certain of the Department's hydroelectric projects are described below. See also "–Renewable Power Initiatives."

Castaic Pump Storage Power Plant. The Castaic Pump Storage Power Plant is located near Castaic, California (the "Castaic Plant") just before the terminus of the west branch of the California Aqueduct at Castaic Lake. The Castaic Plant is the Department's largest source of hydroelectric capacity and consists of seven units. The Castaic Plant's net maximum capacity and net dependable capacity for the seven units is 1,265 MWs. The seven units completed a modernization process in August 2016. A FERC license pursuant to which the Department operates the Castaic Plant expires in 2022. The Department, in partnership with the California Department of Water Resources (the "CDWR"), is in the process of renewing this FERC license. FERC has not issued a new license. Under federal regulations, FERC issued an annual license on February 3, 2022, for the continued operations of Castaic Power Plant under the current license conditions. This annual license will be automatically renewed until FERC issues a new license. 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 CDWR, which has frequently been the subject of litigation that generally alleges that the CDWR is illegally "taking" listed species of fish through operation of the State Water Project export facilities and that the CDWR should cease operation of the State Water Project pumps. The CDWR has altered the operations of the State Water Project to accommodate certain listed species, which has had the effect of reduced pumping from the affected waters. Future litigation of this nature 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 type of litigation will have on the Power System. 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 the State. The aggregate net dependable capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 45 MWs and the net maximum capacity totals 122 MWs.

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 1995, the total aqueduct exports from Owens Valley to the City have gone from approximately 400,000 acre-feet per year to currently 278,000 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 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.

San Francisquito Canyon and the Los Angeles and Franklin Reservoirs. The Department also owns and operates twelve hydroelectric 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 26 MWs and the net maximum capacity totals 78 MWs.

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. Also, the Department benefits from distributed generation ("DG") capacity connected to the Department's grid from customer solar photovoltaic installations through net metering and customer generation rates and from other DG units through a Feed-in-Tariff. These interests, as of January 31, 2022, are summarized in the following chart and discussed below. Each project participant with respect to jointly-owned units is generally responsible for providing its share of construction, capital, operating, decommissioning, and maintenance costs.

Type	Number of Facilities	Department's Net Maximum Connected Capacity (MWs)	Department's Net Dependable Connected Capacity (MWs)
Coal	1	1,202[(1)]	1,202
Natural Gas	1	578	483
Large Hydro	1	496[(2)]	353[(2)]
Nuclear	1	387[(3)]	380
Renewables/Distributed Generation	59,790[(4)]	3,078	936[(5)]
Total	**59,794**	**5,741**	**3,354**

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

(1) 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.

(2) The Department's Hoover Power Plant contract entitlement is 496 MWs, 23.92% of the Hoover total contingent capacity. As of January 20, 2022, low water levels, procedures relating to the operation of Lake Mead, and scheduled maintenance activities have reduced the Department's dependable capacity to approximately 353 MWs. See "*Hoover Power Plant*" below.

(3) 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.

(4) The Department's contract renewable resources in-service include a hydro unit in the Los Angeles area, wind farms in Oregon, Washington, Utah and Wyoming, and customer solar photovoltaic installations and other DG units located in the Los Angeles region.

(5) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

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 MWs (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah; (ii) a ±500 kilovolts ("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.

Power Contracts. Pursuant to a Power Sales Contract with IPA (the "IPP Contract"), the Department is entitled to 48.617% of the capacity of the IPP (currently equal to 875 MWs). The term of the IPP Contract ends on June 15, 2027.

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 an additional 18.168% of the capacity of IPP (currently equal to approximately 327 MWs), subject to recall as described below. The IPP Contract requires 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 2020-21, the IPP operated at a plant net capacity factor of 46.31% and provided approximately 7.3 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes 4.7 million MWhs to the Power System.

Intermountain Generating Station upon the termination of the IPP Contract. In order to facilitate the continued participation of the Department and other power purchasers in the IPP beyond the IPP Contract's termination in 2027, the IPA Board issued the Second Amendatory Power Sales Contract which amended the IPP Contract to allow for the repowering of the plant to replace the coal units with combined cycle natural gas units by July 1, 2025 that would allow for compliance with greenhouse gas ("GHG") emissions performance standards. Pursuant to the provisions of the power sales contracts, the IPP participants also agreed to reduce the initially planned generation capacity from 1,200 MWs to 840 MWs. IPA released a request for proposals in June of 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with green hydrogen fuel (i.e. hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% green hydrogen starting in 2025 and the subsequent goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. This request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was established in early 2022 securing a portion of the required underground salt cavern storage capacity, along with energy conversion services. This contract will provide the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units in 2025. It is estimated that the new combined cycle units at IPP will cost approximately $1.3 billion, and upgrades to the Switchyard and replacement of converter stations will cost approximately $1.2 billion. The original power sales contracts, including the IPP Contract, will terminate on June 15, 2027, at which point the Renewal Power Sales Contracts—which were executed in 2015—will immediately take effect and continue for a term ending in 2077. Most of the power purchasers under the original power sales contracts will continue to be IPP participants under the Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the Renewal Power Sales Contracts. The city of Burbank will take a smaller share of generation capacity under the Renewal Power Sales Contracts, and the Department and the City of Glendale both increased their respective generation shares. In connection with the execution of the Renewal Power Sales Contracts in 2015, the Department also executed successor excess power sales agreements with certain other IPP participants which will continue to make available to the Department additional capacity in the IPP. The increase to the Department's share and additional available capacity in the IPP will become available to the Department when the Renewal Power Sales Contracts take effect on June 16, 2027.

In order to finance certain initial costs of the repowering of the IPP, the IPA has entered into a bond purchase agreement with Royal Bank of Canada that provides access to a flexible drawdown bond in an

amount not to exceed $100 million, of which, $88.5 million has been drawn upon through February 1, 2022. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Power Recalls. Under the existing IPP Excess Power Sales Agreements, certain IPP participants have a right 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. Certain IPP Utah participants have recalled 4.31% of the capacity of IPP (equal to 78 MWs) from the Department for the upcoming summer season and recalled 1.462% (equal to 26 MWs) from the Department for the upcoming 2023 winter season. The percentage of the capacity of IPP subject to recall will not change in 2027 upon the effectiveness of the Renewal Power Sales Contracts described above. The Department can give no assurance that the capacity of IPP subject to recall from the Department under the IPP Excess Power Sales Agreement will not be recalled in the future in accordance with the agreement terms.

Fuel Supply. IPA buys coal under contracts to fulfill the supply requirement of approximately 4.0 million tons per year. Coal is purchased under a portfolio of fixed price contracts that are of short and long-term in duration. Supply chain issues with respect to energy commodities, including coal, impacted coal supply beginning in the later months of 2021 and is expected to impact coal supply in 2022. However, the impact of such supply chain issues on the Department's operations is expected to be minimal. The cost of coal delivered to the Intermountain Generating Station is on par with market prices for the region. IPA expects the costs to fulfill IPP's annual coal supply requirements 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 Union Pacific Railroad company, and the coal is transported, in part, in IPA-owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks.

For more information on the effect of certain environmental considerations on IPP, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Air Quality – Mercury*."

Apex Power Project. The Apex Power Project (the "Apex Power Project") is located in an unincorporated area of Clark County, north of Las Vegas, Nevada. The Apex Power Project includes the Apex Generating Station, which is a combined cycle generating station consisting of one 238 MW, nameplate rating, steam turbine generator, and two simple cycle, 203 MW, nameplate rating, 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, all necessary noise control equipment, and its associated real property. The Apex Generating Station has a net maximum capacity of 578 MWs and a net dependable capacity of 483 MWs. In March 2014, SCPPA acquired the Apex Power Project for the benefit of the Department, and the Department is entitled to 100% of the capacity and energy of the Apex Power Project under a take-or-pay power sales contract with SCPPA. 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 at Lake Mead, 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 ("Western") for 23.92% of total contingent capacity and 14.65% of the firm energy from the Hoover Power Plant through September 2067. This is approximately 496 MWs of contingent capacity and between 199 MWh of firm energy in the winter and 464 MWh of firm energy in the summer. The facility is owned and operated by the United States Bureau of Reclamation (the "Bureau of Reclamation"). Having identified potential for integrating renewable energy and increasing the power plant capacity factor at the Hoover Power Plant, the Department has completed the economic and engineering feasibility studies of implementing the Boulder Canyon Pumped Storage Project ("BCPS") at the Hoover Power Plant. The economic feasibility study revealed that the BCPS operational benefits are not sufficient to offset the multi-billion dollar construction costs of BCPS. Consequently, the Department is considering the feasibility of other less capital intensive hydro-pumped storage projects. See "THE POWER SYSTEM – Renewable Power Initiatives – *Energy Storage Development*."

Low Capacity Forecast. The Bureau of Reclamation's 17-Month Operating Schedule estimates the lowest capacity level to occur in February 2023, due to low water levels, the implementation of a drought contingency plan, procedures relating to the operation of Lake Mead, and scheduled maintenance activities. The minimum Hoover Power Plant capacity in February 2023 is expected to be 910 MWs with a potential maximum capacity of 1,315 MWs for the same month. The Department's share of the total capacity is 23.92%.

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 (the "USFWS") a Biological Assessment on the effect of its operations of the lower Colorado River on endangered species therein (the "Biological Assessment"). After the Biological Assessment was filed, the USFWS 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 of the Biological and Conference Opinion on future operations will be minor; however there is a possibility that future regulatory action will recommend major remediation actions that 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 USFWS 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") expiring in 2025, 2026, and 2027, respectively. 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.

Arizona Public Service Company ("APS") is the operating agent for PVNGS. On average, PVNGS provided over 3.1 million MWhs of energy annually to the Power System. 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; 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.

The aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan prompted the U.S. nuclear industry to form a task force under the direction of PVNGS's Chief Nuclear Officer to take immediate actions in ensuring the reliability of all U.S. nuclear plants. PVNGS instituted improvements driven by the findings from such task force. Among these improvements, is a staging of "flex" equipment, which includes mobile pumps, generators, hoses, and fire trucks that enable PVNGS to shift cooling water through the plant and power critical equipment in the event of a disaster.

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 the 2020 annual funding status report which is based on a 2019 study of decommissioning costs, which 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 84% funded and that its share of decommissioning costs through SCPPA was 100% funded. The Department's direct share of costs is $177 million and SCPPA's share is $186.4 million, of which the Department's portion is $124.9 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 7% per annum investment return on the decommissioning funds and cost increases have been averaging less than 5% per annum. 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 OF WATER AND POWER OF THE CITY OF LOS ANGELES – 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. 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, 2022, 152 casks, each containing 24 spent fuel assemblies, and 11 new casks, each containing 37 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel at a time, have been stored. 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.

Mohave Generating Station – Operations Ceased. 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 30% interest in the Mohave Generating Station. The other co-owners are Edison and NV Energy (formerly known as Nevada Power Company). 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. As required by the Nevada Division of Environmental Protection, 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. The co-owners of the Mohave Generating Station in accordance with an approved site disposition plan, have made approximately 80% of the property of the Mohave Generating Station available for public sale. Any sales transaction will require approval from the Board and City Council. The remaining property would be retained by the co-owners for ongoing monitoring, maintenance, and environmental compliance purposes. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Coal Combustion Residuals*."

Navajo Generating Station – Operations Ceased. The Navajo Generating Station was a coal-fired, electric generating station located near the City of Page, Arizona, that ceased operations in November 2019. 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") is the operating agent of the Navajo Generating Station. The Department sold its interest in the Navajo Generating Station in 2016, however the Department is still responsible for its portion of decommissioning costs.

In February 2020, the City Council instructed the Department to determine the feasibility of entering into partnerships with the Navajo Nation to implement cost-effective solar and clean energy projects for the City, while ensuring environmental justice and equity to the Navajo Nation. The Department is currently seeking partnerships and collaborations with the Navajo Nation on such projects.

LA100 Study

In accordance with three City Council motions passed in 2016 and 2017, the Department partnered with the National Renewable Energy Laboratory (the "NREL") to perform the "LA100: The Los Angeles 100% Renewable Energy Study" (the "LA100 Study"). This unprecedented, three-year study identified several pathways that would allow the City to achieve a 100%-renewable-energy portfolio no later than 2045. The NREL identified four overall scenarios with various modeling assumptions for the Department to achieve its sustainability goals, including one scenario to achieve its goals by 2035. The NREL also analyzed how the scenarios could affect the region's air quality, GHG emissions, public health, jobs, and economic activity. At the direction of the City Council, the study incorporated the CalEnviroScreen, allowing the NREL to identify pathways that will be not only economical for the utility but also equitable for communities.

The LA100 Study has yielded a tremendous amount of data and new, state-of-the-art models that provide the Department with a variety of perspectives on approaches toward 100% renewable energy. The results of the LA100 Study will continue to inform the Department's internal planning processes, including its Strategic Long-Term Resource Plan and other public outreach efforts that are designed to ensure a just and equitable transition for the City. The Financial Services Organization of the Department has conducted a preliminary rate analysis to determine the rate impacts for each of the scenarios in the LA100 Study. However, more in-depth analysis on the specific path is needed to ascertain more accurate rate analysis.

The total cumulative cost of new investment needed to achieve the suite of modeled scenarios ranges from approximately $57 billion to $87 billion, depending on the scenario, load projection, and the target year.

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 ("SBX 1-2"), the California Global Warming Solutions Act of 2006 ("AB32" or the "Global Warming Solutions Act"), the Clean Energy and Pollution Reduction Act of 2015 ("SB 350"), and The 100 Percent Clean Energy Act of 2018 ("SB 100"). See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments." For a discussion of certain State legislation and regulations affecting the Department, including AB32, SB 350, SB 1368, SBX 1-2, and SB 100 see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments." Certain components of the Department's renewable power resource portfolio are described below. Available capacity with respect to such renewable power resources will vary as they are intermittent resources. Wind power, both obtained through power purchase agreements and resources owned by the Department, provided 10% and 11% of the Department's energy in 2019 and 2020, respectively, or about one-third of the renewable energy, which comprised 34% and 37% of the total energy mix in 2019 and 2020, 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, and is expected to be generated in New Mexico, as described under "THE POWER SYSTEM – *Renewable Power Initiatives – Red Cloud Wind Project*." Such power purchase agreements provide for an aggregate of 1,195 MWs of wind energy. In addition to these power purchase agreements, wind farms with output of approximately 880 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") began commercial operation in November 2009 and 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 expiring in November 2029 (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 MWhs of energy from the Milford I Facility over the 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") began commercial operation in May 2011 and 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 expiring on June 30, 2031 (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 4,467,600 MWhs of energy from the Milford II Facility over the 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 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") began commercial operation in June 2010 and 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. Energy from the Linden Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Linden Project to the Pacific DC Intertie. 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 for a term expiring in 2035 (unless earlier terminated). In addition, the Department has purchased the City of Glendale's 10.00% output entitlement share of the Linden Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations." On February 10, 2020, Senvion GmbH, the operations and maintenance ("O&M") contractor at the Linden Project informed SCPPA and the Department that Senvion GmbH would cease performing service under the O&M contract on February 29, 2020. Senvion GmbH had previously filed for insolvency under German law and cited the German Insolvency Act, section 103, as the basis for declaring non-performance under the O&M contract. On February 18, 2021 Vestas-American Wind Technology, Inc. was awarded the service and maintenance contract for turbine maintenance at the Linden Project. Crews were on-site on February 23, 2021, and have assumed operations and maintenance responsibilities.

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and 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 expiring in 2030 (unless earlier terminated). Energy from the Windy Point Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs 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 the City of 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 (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 began commercial operation in June 2010 and has a nameplate capacity of 135 MWs. 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

conducting advanced monitoring studies and surveys to research golden eagle behavior within the vicinity of the Pine Tree Wind Project and to determine potential causes of the eagle mortalities and mitigation options relating to the golden eagles. The Department previously conducted tests using radar and automated deterrent technology in detecting and deterring 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. As of June 2017, the Department entered into a settlement agreement with the USFWS to address the golden eagle mortalities at the Pine Tree Wind Project and is in the process of completing all actions required under the settlement agreement, which are not expected to have an adverse impact on the operations of the Pine Tree Wind Project. The Department has completed its golden eagle research and development study as required by the settlement agreement and submitted the final summary report to USFWS in September 2020. On December 29, 2020, the Department received a letter from the USFWS that it had fulfilled the terms of the settlement agreement including the research and development study, payment, and meet and confer with USFWS staff. The Department is still coordinating with the USFWS to obtain an incidental take permit for golden eagles as a separate requirement under the settlement agreement. In order to protect condors, a protected species under State and federal law, the Department has implemented a condor detection protocol that includes turbine curtailment when condors are observed in the immediate area. Additionally, the Department is developing a condor conservation plan in coordination with the USFWS and is seeking to obtain an incidental take permit for California condors. The condor conservation plan outlines the avoidance measures that are currently being implemented and the proposed compensatory mitigation measures in an effort to protect and address the declining condor population.

Red Cloud Wind Project. In November 2020, the Department entered into a power sales agreement with SCPPA to purchase renewable energy purchased by SCPPA from the Red Cloud Wind Project located in New Mexico (the "Red Cloud Wind Project"). Pursuant to a power purchase agreement with Red Cloud Wind, LLC, SCPPA purchases 331 MWs of renewable energy to be delivered to the Department at the Navajo 500 kV Switching Station for a 20-year term. The Red Cloud Wind Project was developed by Pattern Energy and commenced commercial operation on December 22, 2021. The Red Cloud Wind Project is expected to deliver an annual average of approximately 1,333,000 MWhs of renewable energy to the Department.

Solar Power Programs. The Department has implemented the following 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, which ended in December 2018; (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; (iv) the Solar Rooftops Program which places Department-owned solar panels on qualifying residential rooftops in exchange for predefined lease payments to the customer; (v) a Feed-in-Tariff ("FiT") program, launched on February 1, 2013, which has 84.7 MWs of solar photovoltaic generation and 2.95 MWs of renewable landfill gas installed within the Department's service territory and connected to the Department's electric distribution system; (vi) the Board-approved pilot Shared Solar Program ("SSP"); (vii) the Virtual Net Energy Metering ("VNEM") pilot program, which launched in March 2021 and allows developer or building owners to install solar arrays on multi-family dwelling unit buildings and split the energy sales proceeds with tenants; and (viii) the FiT Plus program, which facilitates the installation of battery storage with existing and new FiT projects.

Under the California Solar Initiative ("SB-1"), 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 Solar Photovoltaic Incentive Program used $320 million of ratepayer funds mandated by SB-1 to administer the program and subsidize customers for customer-owned solar projects

to offset their electricity use. As of December 2018, the Department committed all funds available for this program for 296 MWs of installations.

The Department currently has 25.2 MWs of Department–built solar projects on City-owned properties. The Adelanto Solar Power Project is a 10 MW solar photovoltaic system placed into commercial operation in June 2012, which is expected to deliver 500,000 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 in March 2013. The Pine Tree Solar Project is an 8.5 MW solar photovoltaic system expected to deliver 425,000 MWhs of energy over the next 25 years, located at the Department's existing Pine Tree Wind Project in the Tehachapi Mountains, California. The remaining 6.7 MWs includes installations spread across various City owned properties in the Los Angeles Basin as well as a 500kW system in the Owens Valley.

The Department has entered into the following eight power purchase agreements ("PPAs") for the purchase of renewable energy from 1,245 MWs of solar photovoltaic projects:

- One PPA with an option to purchase is a 25-year contract with K Road Moapa Solar, LLC, which changed its name to Moapa Southern Paiute Solar, LLC, for 250 MWs, delivering up to 618,000 MWhs a year to the Department. The solar facility is located on Moapa Band of Paiute Indians tribal land north of Las Vegas, Nevada. The Department acquired the approximately 5.5-mile transmission line associated with the facility, which achieved full commercial operation in December 2016.

- The second PPA with an option to purchase is a 20-year contract through SCPPA for 210 MWs of the Copper Mountain Solar 3 Project 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 and began full commercial operation in April 2015.

- The third PPA with an option to purchase is a 20-year contract for 60 MWs of the RE Cinco Solar Project developed by Recurrent Energy, an affiliate of Canadian Solar Inc. RE Cinco Solar Project is near the Mojave Desert in Kern County and is expected to deliver an annual average of 182,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in August 2016.

- The fourth PPA with an option to purchase is a 25-year contract through SCPPA for 105 MWs of the Springbok I Solar Farm Project developed by 8minutenergy. Springbok I Solar Farm Project is near the Mojave Desert in Kern County and is expected to deliver an average of 284,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2016.

- The fifth PPA with an option to purchase is a 27-year contract through SCPPA for 155 MWs of the Springbok II Solar Farm Project, which is adjacent to the Springbok I Solar Farm Project and was developed by 8minutenergy. Springbok II Solar Farm Project is expected to deliver an average of 420,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in September 2016.

- The sixth PPA with an option to purchase is a 27-year contract through SCPPA for 90 MWs of the Springbok III Solar Farm Project, which is adjacent to the Springbok I and Springbok II Solar Farm Projects and was developed by 8minutenergy. Springbok III Solar Farm Project

is expected to deliver an average of 240,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2019.

- The seventh PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 1, is a 25-year contract through SCPPA for 175 MWs of energy and 131.25 MWs/525 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 1 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 2, and is being developed by 8minutenergy, with commercial operation expected in the first quarter of calendar year 2023. Eland Solar & Storage Center, Phase 1 is expected to deliver an average of approximately 702,000 MWhs of renewable energy a year to the Department.

- The eighth PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 2, is a 25-year contract through SCPPA for 200 MWs of energy and 150 MWs/600 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 2 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 1, and is being developed by 8minutenergy, with commercial operation expected in the third quarter of calendar year 2023. Eland Solar & Storage Center, Phase 2 is expected to deliver an average of approximately 803,000 MWhs of renewable energy a year to the Department.

In connection with the implementation of these PPAs, the Department has upgraded certain transmission assets to accommodate these projects in the Barren Ridge area. See "Transmission and Distribution Facilities – *Barren Ridge Renewable Transmission Project*."

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. One such public private partnership is the 2,500-acre property purchased from Nextera Energy Resources in 2012 (the "Beacon Property"), which is near the Pine Tree Wind Project. Five PPAs and associated agreements that have been executed for the development of five solar sites totaling 250 MWs within the Beacon Property are generating an average of 581,000 MWhs per year of solar energy over a term of 25 years. Each of the five solar sites has achieved commercial operation at different dates within the years 2016 and 2017. The PPAs provide the Department with an option to purchase the solar projects after the developers have realized the federal tax benefits.

The Department's 150 MW FiT program allows the Department to purchase, through power purchase contracts, electricity generated from program participants' renewable energy generating sources. Such sources will be located within the Department's 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. As discussed above, as part of the PPAs for solar development on the Beacon Property, the Beacon Solar developers installed additional solar in the Department's service territory. The Department has allocated the capacity of the original 150 MW FiT program. The Department expanded the FiT program by an additional 50 MWs in January 2020 and obtained approval from the City Council to expand the FiT program by an additional 300 MWs of capacity. In addition to increasing the FiT program from 150 MW to 450 MW over a number of years, the FiT program will now accommodate all renewable technologies approved by the CEC and expand each project's maximum capacity, previously set at 3 MWs, to 10 MWs. The FiT Plus and VNEM programs will use 10 MWs and 5 MWs of the existing FiT capacity, respectively. The FiT Plus program encourages the installation of battery energy storage with local solar projects, making solar energy dispatchable, while increasing the power grid's reliability and resiliency. The VNEM program facilitates the installation of solar projects on multifamily dwellings, and allows renters to readily access the benefit of these systems

Geothermal Development. The Department executed a power sales agreement with SCPPA for 84.62% of the energy output, or an expected 114 Gigawatt hours (GWhs) annually, of the Don A. Campbell

Phase I Geothermal Energy Project (the "Don Campbell Phase I Project"), which began commercial operation on January 1, 2014. The Don Campbell Phase I 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 expiring December 31, 2033.

In addition, in April 2015, the Department executed a power sales agreement with SCPPA for 100% of the energy output, or an expected 135 GWhs annually, of the Don A. Campbell Phase II Geothermal Energy Project (the "Don Campbell Phase II Project" and, together with the Don Campbell Phase I Project, the "Don Campbell Projects"), which expires in September 2035 and is located in the same vicinity as the Don Campbell Phase I Project. The Don Campbell Phase II Project is an expansion of the Don Campbell Phase I Project by the same developer, Ormat Nevada, Inc., and began commercial operation in September 2015. The nameplate capacity for the Don Campbell Phase II Project is 16.2 MWs.

In addition to the Don Campbell Projects, the Department executed a power sales agreement with SCPPA in September 2013 for a share of the output purchased by SCPPA from the Heber-1 Geothermal Project (the "Heber-1 Project"). The energy delivery commencement date was February 2, 2016 for an initial term of ten years. 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 MWs. The Department's share was 66.67% (30.68 MWs) in the first three years and is 78.0% (35.88 MWs) for the remaining term. The equivalent average energy delivered to the Department is expected to be 285 GWhs annually.

In May 2015, the Department entered into an agreement with Salt River Project to purchase through October 23, 2021 approximately 55 MWs of renewable geothermal energy from Salt River Project's interests in the Hudson Ranch Geothermal Project located in the Imperial Valley in Southern California.

In addition, the Department executed a power sales agreement with SCPPA in December 2016 for a share of the output purchased by SCPPA from the Ormesa Geothermal Complex Project (the "Ormesa Project"). The energy delivery commencement date was January 1, 2018 for a term of 25 years, ending on December 31, 2042. Similar to the Heber-1 Project, the Ormesa Project is an existing geothermal complex which includes two active binary units and one active bottoming unit, located in Imperial County, California. The generation capacity of the project is 35 MWs. The Department's share is 85.71% (30 MWs) of the energy output. The equivalent average energy delivered to the Department is expected to be 250 GWhs annually.

In May 2017, the City Council approved a power sales agreement with SCPPA for 100% of the output purchased by SCPPA from the Ormat Northern Nevada Geothermal Portfolio Project. Once fully in service, this project will provide the Department a minimum of 135 MWs and a maximum of 185 MWs of renewable geothermal energy from five new and five existing power plants in various locations in Nevada. This amount is expected to represent approximately 5% of the Department's renewable energy portfolio in 2030. Energy delivery will step up in three phases from December 31, 2017 to December 31, 2022 as follows: 60 MWs minimum and 85 MWs maximum by December 31, 2018 (which was achieved), cumulative 90 MWs minimum and 130 MWs maximum by December 31, 2020 (which was achieved), and cumulative 135 MWs minimum and 185 MWs maximum by December 31, 2022. After December 2022, the maximum annual energy received by the Power System from the project is expected to be 1,620 GWhs. The power sales agreement with SCPPA expires in December 2043.

Biomass Development. In March 2018, the City Council approved a power purchase agreement with SCPPA for a share of the output of the ARP-Loyalton Biomass Project in Sierra County, California, which began commercial operation in April 2018. SCPPA partnered with other State POUs to purchase a

total of 18 MWs of capacity for a term of five years towards satisfaction of procurement obligations under SB 859. The Department's share of the ARP-Loyalton Biomass Project is 8.9 MWs. In addition, the Department has contracted with SCPPA to purchase 5.4 MWs of rated capacity from the Roseburg SB 859 biomass project. These two projects allow the Department to meet its requirement to purchase 14.3 MWs of rated capacity from biomass sourced energy facilities in order to comply with SB 859. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Biomass Legislation*." In February 2020, SCPPA and the participants in the ARP-Loyalton Biomass Project were informed that the operator and its parent company, American Renewable Power, LLC, filed for Chapter 11 bankruptcy. Under this process, the facility was purchased by Sierra Valley Enterprises, LLC in May 2020. Energy deliveries from the ARP-Loyalton Biomass Project have stopped since February 2020. After the conclusion of bankruptcy proceedings, it is expected that future energy deliveries from the ARP-Loyalton Biomass Project will come from the new owners, Sierra Valley Enterprises, LLC. The Department anticipates that SCPPA will achieve a final settlement agreement for the ARP-Loyalton Biomass Project by the fourth quarter of calendar year 2022, whereby contract deliveries will resume until the original end of the term in 2023.

Energy Storage Development. In connection with the implementation of State law, the Department is developing viable and cost-effective energy storage systems. The goals of the energy storage systems include reducing emissions of GHGs, reducing demand for peak dispatchable generation and improving the reliability of the electric grid. Although energy storage systems themselves are not considered renewable resources, they facilitate the integration of renewable resources into the Power System. To date, the Department has implemented several small energy storage systems throughout the Power System, including:

- The 20 MW Beacon utility-scale battery energy storage system (BESS) project, located on the Beacon Property, which commenced operation in October 2018;

- The 12 kW Fire Station 28 BESS, located near the Porter Ranch area, which commenced operation in October 2017; and

- The 1.5 MW Lithium-Ion BESS, located at the Springbok 3 solar plant, installed in October 2019 for technical and operational performance demonstrations.

- The 100 kW Lithium-Ion BESS and 100 kW Flow BESS, located at the Department's headquarters (John Ferraro Building), which commenced operation in November 2019.

See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Energy Storage Legislation*."

In March 2020, the Department issued a standalone energy storage project RFP through SCPPA. In addition, the Department has entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. See "THE POWER SYSTEM – Renewable Power Initiatives – *Solar Power Programs*."

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 solar and wind energy, 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 9,964 Department customers subscribed to the Green Power Program as of January 31, 2022. 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 renewable energy 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 solar, wind or geothermal and for improved transmission access to geothermal energy. In addition, as part of Mayor Eric Garcetti's announcement in February 2019 that certain natural gas units will be phased out and replaced with renewable energy producing assets, the Department will be exploring options over the next few years to develop such assets for the Power System. See "THE POWER SYSTEM – Department Owned Facilities – *Once-Through-Cooling Units Phase-Out*" for more information. 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 is likely required for the Department's participation in or acquisition of renewable energy projects.

L.A.'s Green New Deal. On February 10, 2020, Mayor Eric Garcetti released his Executive Directive No. 25 implementing L.A.'s Green New Deal. As part of this directive, the City expects the Department to provide equitable access to clean energy programs, build zero carbon microgrids in City owned infrastructure, deploy smart meters City-wide and institute other similar initiatives. The Department is studying how to implement this directive and other renewable power related directives and the effect they will have on the finances and operations of the Power System through its Clean Grid LA Plan.

On April 19, 2021, Mayor Eric Garcetti declared in his 2021 Los Angeles State of the City address that his goal is for the Department to provide an energy mix that is 80% renewable and 97% GHG free resources by 2030, a full six years ahead of the L.A. Green New Deal, and to use the LA100 Study as a guide to fulfill President Biden's energy vision, with a goal of 100% carbon-free energy by 2035. To achieve these goals, the Mayor referenced the Department's transition of Scattergood Generating Station to clean energy alternatives, the construction of the Red Cloud Wind Project in New Mexico, the partnership with the Navajo Nation for solar energy, and the supply of IPP with green hydrogen fuel. For more information on the LA100 Study, see "THE POWER SYSTEM – *LA100 Study*." For more information on the transition of Scattergood Generating Station, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board." For more information on the construction of the Red Cloud Wind Project, see "THE POWER SYSTEM – Renewable Power Initiatives – Red Cloud Wind Project." For more information on the Navajo Project, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units - Navajo Generating Station – Operations Ceased." For more information on the supply for IPP, see "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."

The Clean Grid LA Plan Update was presented to the Board on May 11, 2021. The Clean Grid LA Plan Update is a 10-year roadmap that aligns with the LA100 Study to assist the Department with its clean energy goals. Elements of the Clean Grid LA Plan include providing 80% renewable and 97% GHG free resources by 2030, accelerating transmission projects, transforming local generation, accelerating energy storage, and deploying distributed energy resources equitably. As part of transforming local generation, the Department plans to construct hydrogen capacity at the Scattergood Generating Station while assessing additional green hydrogen capacity at its other in-basin generating stations. In addition, the Department plans to convert Haynes Unit 8 from once-through cooling to wet cooling.

On September 1, 2021, the City Council voted to instruct the Department to "prepare a Strategic Long-Term Resource Plan that achieves 100 percent carbon-free energy by 2035, in way that is equitable and has minimal adverse impact on ratepayers." In addition, the City Council instructed the Department to "create a long term hiring and workforce plan . . . ensuring project labor agreements, [payment of]

prevailing wage[s] . . . [with] hiring from environmentally and economically disadvantaged communities." The Department initiated its Strategic Long-Term Resource Plan in September 2021 with a stakeholder process, and will incorporate the Clean Grid LA Plan and key findings from the LA100 Study for Board consideration.

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, required 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 adopted a goal in August 2014 of achieving up to 15% energy savings by the end of 2020, which has been achieved and is now focused on an additional 15% energy savings by 2030.

Through SB 350, State utilities are expected to double energy efficiency savings by 2030 with an initial evaluation of the actual energy efficiency savings assessed as part of the resource plan expected to be completed in September 2022. Also, the State has required the CPUC and CEC to establish annual targets for statewide energy efficiency savings.

Program and Portfolio Highlights

The balanced portfolio of programs provides opportunities for all customers to benefit from cost effective energy efficiency. This approach targets large energy users and hard-to-reach customers who would not otherwise be able to invest in energy efficiency services, broadly addresses energy end uses in the built environment, focuses on reducing consumption during times of peak demand, and provides quality job opportunities for the local workforce. These programs include financial incentives for the installation of a variety of efficiency measures, free energy saving products, technical assistance incentives for business and industry, codes and standards, and education and awareness. The following list provides examples of programs that demonstrate the portfolio's ability to reach all customer types.

Efficient Product Marketplace. The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point of sale credit option to customers during their online purchases, eliminating the need for completing a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare and choose offers from a list of local third-party vendors.

Food Service Program. For in-store purchases, the Food Service Program offers an instant rebate as a line item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment.

Customer Performance Program. The Custom Performance Program (the "CPP") provides cash incentives for energy savings achieved through the implementation and installation of various energy

efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP's Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP's Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers' individual efficiency projects' energy savings. The CPP has achieved over 582 GWhs of energy savings since 2007.

Commercial Lighting Incentive Program. The Commercial Lighting Incentive Program ("CLIP") offers customers incentives to install newly purchased and installed energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (kW). CLIP's calculated savings approach allows customers to tailor their lighting efficiency upgrades to meet their lighting needs better, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 736 GWhs of energy savings since 2000.

Commercial Direct Install Program. The Commercial Direct Install ("CDI") Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The Department partners with Southern California Gas Company ("SoCalGas") on this program to offer a tri-resource efficiency program aiming to reduce the use of electricity, water, and natural gas. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less; CDI has achieved 446 GWhs of energy savings since its inception in 2008.

Home Energy Improvement Program. The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading/retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the neediest customers.

Refrigerator Exchange Program. The Refrigerator Exchange Program ("REP") is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities, multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third party contractor, ARCA (Appliance Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 103 GWhs.

LED Streetlight Program. The LED streetlight program 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.

Program Analysis and Development Program. The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio, which are not included in individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates

to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California.

The Department has also partnered with the NREL to develop a technology prioritization tool as the Department ramps up its technology assessment efforts in the Emerging Technologies program. The tool helps prioritize the most impactful technologies that would improve energy efficiency for customers. These technology assessment efforts in the Emerging Technologies program incorporate many of the tools and methods used in the LA100 Study. See "– LA100 Study" above.

The set of tools and methods used in the LA 100 Study allows the Department to assess potential impacts as it relates to an emerging technology using the development of the building demand modeling that includes baseline consumption and characteristics data for residential and commercial building stock. This effort will analyze multiple use cases to empower the Department to provide more accurate potential studies and develop a pipeline of new technology assessments to determine the appropriate intervention required to get maximum benefits. The goal is to quantify achievable contributions towards goals set by State and local energy policies for the lowest cost.

From 2000 through January 2022, the Department has spent approximately $1.5 billion on its energy efficiency programs, and these programs have reduced long-term peak period demand and consumption by approximately 898 MWs and resulted in approximately 5,057 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers saved approximately 300 GWh incrementally for the Fiscal Year 2020-21, falling short of energy savings targets by 60 GWh. As a result of COVID-19 restrictions, some residential rebate programs were temporarily suspended to prioritize the health and safety of customers, employees, and contractors. The Department spent approximately $107 million on energy efficiency programs for Fiscal Year 2020-21 of its approximately projected $172 million budgeted amount for such Fiscal Year. The CLIP and CPP adjusted operations to continue processing rebate applications and payments during the pandemic without interruption. As the situation around COVID-19 evolves, the Department will continue to evaluate the delivery and implementation of energy efficiency measures that support system reliability and resiliency while enabling customers to manage their power better. The Department anticipates increasing its expenditures for energy efficiency programs in future years, based on portfolio planning utilizing the results of the Department's Energy Efficiency Potential Studies. As a result of the Department's 2014 Energy Efficiency Potential Study, the Board adopted the goal of reducing usage by 15% by the end of 2020 compared to 2010 levels. This was significantly above the 10% energy reduction target set by the State. The Department has achieved its energy efficiency goal for 2020 and is now focused on an additional 15% energy savings by Fiscal Year 2030-31.

Additionally, while COVID-19 restrictions impacted everyday life, building operators and maintenance workers throughout the City remained on the frontlines to ensure their facilities' safe and efficient operation. In support of their efforts, the Department's Custom Performance Program adjusted its operations to work with its engineering services providers to develop new remote verification processes to enable the program to continue the vital work of processing rebate applications and payments during the pandemic without interruption.

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

Natural gas is used to fuel 100% of the Los Angeles Basin Stations. The Department's fossil fuel requirements for the Los Angeles Basin Stations to meet the electric load requirements of its customers in the City (referred to as "native load") were 47 billion equivalent cubic feet of natural gas during Fiscal Year 2019-20. In addition, the Department's fossil fuel requirements for the Apex Power Project were 19.265 billion equivalent cubic feet of natural gas during Fiscal Year 2020-21. In the early 2000s, the

Department determined that acquiring natural gas reserves was 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 leases of gas producing property in Sublette County, Wyoming. This acquisition provided approximately 5% of the Department's average daily natural gas requirements for Fiscal Year 2020-21. 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 (8) Derivative Instruments" of the Department's Power System Financial Statements. 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, 2022, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2025-26 with an aggregate notional amount of approximately 49.9 million MMBtus. These financial hedges cover approximately 5% to 48% of the Department's natural gas requirements based on the latest budget for the Fiscal Years through 2025-26. 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 as of June 30, 2021 and 2020, can be found in Note (8).

The Department has previously used a physical delivery natural gas hedge program that was designed to hedge up to 50% of its forecasted usage. However, due to the limitation of gas injections at the SoCalGas Aliso Canyon storage facility, there is some uncertainty about intrastate gas transmission capacity available for electric generators. Consequently, the Department reduced the amount of forward physical gas purchased and limited the term of forward purchases based on the Department's quarterly term plan forecasting periods.

The Department has firm interstate natural gas transportation capacity on the Kern River Pipeline System. The total amount of capacity is sufficient to transport 92% of the average amount of natural gas needed for the Los Angeles Basin Stations under current Department forecasts. 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 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.

As of January 31, 2022, approximately 45% and 34% of the Department's projected natural gas needs have been hedged for Fiscal Year 2022-23 and Fiscal Year 2023-24, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2026-27, approximately 3% of projected natural gas needs are hedged. The Department typically hedges a higher percentage of its natural gas needs as the operating year approaches. The goal of the current natural gas hedging program is to hedge up to five years forward from the current Fiscal Year, with the next Fiscal Year hedged up to 50% and the fifth Fiscal Year hedged up to 10%. The Department periodically reviews the goals of its natural gas hedging program.

The SoCalGas Aliso Canyon underground natural gas storage facility in the Porter Ranch area of Los Angeles leaked between October 23, 2015 and February 18, 2016 and was ordered to cease its injections by State agencies until testing of all operating wells has been completed. The volume in this storage field, SoCalGas's largest, has been reduced for safety reasons to a maximum of only 34 billion cubic feet ("BCF"), from its design maximum of 86 BCF. Although the required safety inspections are ongoing, the CPUC has allowed limited operation at Aliso Canyon to maintain gas pipeline and bulk electric system operational reliability. In August 2019, the CPUC approved a revision of the Aliso Canyon Withdrawal Policy, removing the designation "facility of last resort," allowing SoCalGas more flexibility to withdraw from the storage field to maintain pipeline integrity. Since this change in policy, SoCalGas has been able to withdraw from the storage field more freely, thus reducing the volatility in both the volume of locally available natural gas and local natural gas pricing. There have been no localized natural gas curtailments impacting the Department and there have been no impacts to the Department from SoCalGas operations thus far.

In August 2018, then-California Attorney General Xavier Becerra, along with the California Air Resources Board ("CARB"), the City and Los Angeles County (the "County"), announced a $119.5 million settlement with SoCalGas over the natural gas leak at Aliso Canyon described above, which was approved by the court in February 2019.

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 SWRCB and the City's plans to eliminate the future use of once-through-cooling for these plants and replace them with clean energy alternatives. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – 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*." The Valley Generating Station, which is located inland, utilizes recycled water for cooling.

Spot Purchases

The Department purchases 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 Power System operation. In addition, purchases of energy are made from other entities located in the Southwest. Spot purchases have generally been made at prices that permit economical operation of the Power System and that are comparable to the Department's costs for producing power from its own resources.

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. The Department has increased its volume activity with the Cal ISO, including the purchase and sale of energy, as well as providing ancillary services, when excess capacity exists on its system.

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 (primarily by applying revenues to the costs of capital improvements or toward an electric rate stabilization account in the Incremental Electric Rate Ordinance). With equipment outages, retirement of equipment, anticipated load growth and changes in GHG 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 26,024 miles of alternating current ("AC") and direct current ("DC") transmission and distribution circuits operating at voltage classes ranging from 120 volts to 500 kV, of which 22,268 miles are above ground. In addition to using its transmission system to deliver

electricity from its power generation resources, under the OATT 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, at the direction of and for the benefit of the respective co-owners/participants, 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 in the Cal ISO market.

On April 1, 2021, the Department began participating in Cal ISO's Western EIM. The EIM is a real-time energy market that provides sub-hourly dispatch of participating resources for balancing supply and demand every five minutes, using the least-cost energy. As an EIM participant, the Department will voluntarily provide excess energy capacity for dispatching to other participating utilities, while maintaining control of its generation assets and ratemaking authority. The Western EIM also provides an opportunity for the Department to purchase low-cost excess energy. The Department is participating voluntarily in order to tap into resources across a larger geographic area that includes nine western states and the Canadian Province of British Columbia. The Department expects its participation in the EIM to improve reliability, lower the cost of delivery of renewable power and other power resources to its customers, and foster integration of renewable energy.

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 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. After the completion of an upgrade to its capacity in December 2010, a maximum of 2,400 MWs can be transmitted over the STS. The Department's entitlement in the capacity of the STS is currently approximately 1,428 MWs and is expected to increase to 2,172 MWs in 2027 as a result of the Department increasing its share of the STS to 90.5% in accordance with the Renewal Power Sales Contract. IPA is expected to replace the existing Adelanto Converter Station and IPP Converter Station with new HVDC stations on available land adjacent to the existing converter stations at Adelanto and IPP, which replacement is currently scheduled for a commercial operation date in April 2026. The new converter stations would tie into the existing AC switchyards and connect to the existing DC transmission line. The Department entered into a transmission service contract

with SCPPA in 1983 to define the terms for transmission service for the Department's 59.5% entitlement right to capacity in the STS that it assigned to SCPPA in order for SCPPA to incur indebtedness sufficient to generate funds to finance the original construction of the STS. This service provides for the transmission of energy from the IPP Converter Station to the Adelanto Converter Station until 2027. The Department has negotiated a renewal transmission service contract with SCPPA for the same purpose as the original transmission service contract to allow SCPPA to be able to continue handling financings of the STS for the remainder of the Department's participation in the IPP until 2077.

Northern Transmission System. The Northern Transmission System (the "NTS") includes two approximately 50-mile, 345 kV AC transmission lines from IPP to the Mona Substation in Northern Utah, and one approximately 144-mile, 230 kV AC 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 MWs; the capacity from Mona to IPP is 1,200 MWs; the capacity from IPP to Gonder is 200 MWs; and the capacity from Gonder to IPP is 117 MWs.

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 3,210 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 Transmission Line. The Devers-Palo Verde 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 Transmission Line from Edison (the "Devers-Palo Verde Agreement") at the rate being charged by the Cal ISO for that same service. 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 259-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 currently owned by SCPPA, APS, Salt River Project, Western and Startrans IO, L.L.C. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Phoenix Transmission Project for the benefit of the Department through the purchase of the M-S-R Public Power Agency ("M-S-R") ownership share (11.53850% of the Westwing-Mead component and 8.09930% of the Mead-Marketplace component) of the Mead-Phoenix Transmission Project. After such acquisition, the Department's share is 57.7320% of SCPPA's member-related interests in the Westwing-Mead component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 29.8462% of the entire Westwing-Mead component of the Mead-Phoenix Transmission Project) and 39.6459% of SCPPA's member-related interests in the Mead-Marketplace component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 30.5075% of the entire Mead-Marketplace component of the Mead-Phoenix Transmission

Project). A maximum of 1,923 MWs can be transmitted over the Westwing-Mead component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 332 MWs. A maximum of 2,600 MWs can be transmitted over the Mead-Marketplace component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 315 MWs. The Department's average share of the Mead-Phoenix Transmission Project components is 50.39% of SCPPA's member-related interests in the Mead-Phoenix Transmission Project. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Phoenix Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Phoenix Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in 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, currently, SCPPA, Western and Startrans IO, L.L.C., in connection with the Mead-Phoenix Transmission Project. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Adelanto Transmission Project for the benefit of the Department through the purchase of M-S-R's 17.5% ownership share of the Mead-Adelanto Transmission Project. After such acquisition, the Department's share is 48.878% of SCPPA's member-related interests of the Mead-Adelanto Transmission Project (SCPPA's member-related interests comprise 85.4167% of the entire Mead-Adelanto Transmission Project). A maximum of 1,291 MWs can be transmitted over the Mead-Adelanto Transmission Project, of which the Department has an entitlement share of 539 MWs. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Adelanto Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Adelanto Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Adelanto Transmission 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 Project 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 now-retired 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 Project, 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 Co-Tenancy and Operating Agreement, the Department is a 30% co-owner of the Mohave Switchyard, a 29.3% co-owner of the 500 kV switchyard, an 11.3% owner of the 220 kV switchyard, and a 15.1% co-owner of the transformers between the 500 kV and 220 kV switchyards, each of which is a part of the Eldorado Substation. The Department's ownership represents 716 MWs of capacity on the Mohave-Eldorado transmission line and 215 MWs of capacity on the two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines.

Barren Ridge Renewable Transmission Project ("BRRTP"). The Department's BRRTP involves expansion of the Barren Ridge Switching Station in order to increase the transmission capacity of renewable energy flowing into the Los Angeles Basin from generating facilities in Owens Valley, Kern County and the Tehachapi Mountains by 2,000 MWs.

Projected Capital Improvements

The Department has developed a series of Power System 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 resource plan was published in December 2017.

Based on the Department's June 2021 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2019-20 to Fiscal Year 2029-30 at a forecasted rate of approximately 1.66% 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 and battery electric vehicles. In the Power System's most recent 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 the end of 2020, are anticipated to result in net overall energy consumption that increases by 0.04% per year over this period. The Department achieved its energy efficiency goal for 2020 and is now focused on an additional 4,347 GWh of energy savings by 2035. Enhancement and expansion of electric transmission resources will enable access to renewable energy resources. Certain in-basin energy projects 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.

Power System Reliability Program. A significant power outage in 2006 caused the Department to conduct an evaluation of its electrical infrastructure and led to the development of a comprehensive distribution-focused power reliability program called **"**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, (c) replacement cycles at the facilities that are in alignment with the equipment's life cycle such as replacing aging underground cables, overhead poles and circuits and substation equipment and (d) replacement of overloaded transformers. In 2013, another evaluation was completed and the program was expanded and renamed the **"**Power System Reliability Program.**"** The Power System Reliability Program assesses all Power System assets affecting reliability in an integrated and comprehensive manner and proposes 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 for all major functions of the Power System, including distribution, transmission, generation, and substations. The Power System Reliability Program has been and 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 2021-22 through Fiscal Year 2025-26, the Department expects to invest approximately $10.9 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2021
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$ 2,966
IT Infrastructure*	753
Energy Efficiency	955
Power System Reliability Program	3,214
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	1,924
Power System Resource Plan	16
Shared Services: Facilities, Customer Services, Fleet	1,118
Total Power System Capital Improvements	$10,947

* For planning purposes, the power financial plan includes a proposed IT Cost Adjustment Factor (ITCAF) with an assumption of a commencement date of July 1, 2022. This proposed ITCAF is designed to recover the information technology (IT) expenses related to enterprise resource planning, smart grid, cybersecurity, and cloud infrastructure programs. These IT expenses include both capital and operation and maintenance expenses that are being allocated among base revenue supported categories such as operating support, infrastructure and other pass-through supported categories.

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

The table below indicates, for Fiscal Year 2021-22 through Fiscal Year 2025-26, 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)

Fiscal Year Ending (June 30)	**Internally Generated Funds**	**External/Debt Financing**	**Total Capital Expenditures[(1)]**
2022	582	1,298	1,881
2023	796	1,254	2,050
2024	953	1,162	2,115
2025	1,082	1,212	2,295
2026	1,221	1,385	2,607
	$4,635	$6,312	$10,947

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

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, including with respect to the COVID-19 pandemic. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – COVID-19 Pandemic." 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 particular times and (xiii) delays in approvals of rate increases. No assurance can be given 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.

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OPERATING AND FINANCIAL INFORMATION

The Department's service area consists of the City, where over 1.5 million customers are served, and certain areas of Inyo and Mono Counties in the State, where approximately 5,182 customers are served. As of December 31, 2021, 32% of the Power System's total energy sales (measured in MWhs) were to residential customers, 58% to commercial and industrial customers and the remaining 10% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately 36%, 58%, and 6% 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)

	Six Month Period Ended December 31[1]		Fiscal Year Ended June 30				
Operating Statistics	**2021**	**2020**	**2021**	**2020**	**2019**	**2018**	**2017**
Net Energy Load[2]	12,585	13,046	23,797	24,096	25,046	25,857	26,460
Net Hourly Peak Demand (MWs)	4,883	6,106	6,106	5,637	6,201	6,432	5,762
Annual Load Factor (%)	58.34	48.37	44.49	48.66	46.11	45.89	52.42
Electric Energy Generation, Purchases and Interchanges[2]							
Generation[3][4]	11,114	10,177	17,281	17,947	16,862	13,993	14,589
Purchases[4]	4,184	3,919	8,988	7,295	8,966	12,297	12,168
Miscellaneous Energy Receipts[2]	0	694	705	470	230	–	–
Total Energy[2]	15,298	14,790	26,974	25,712	26,058	26,290	26,757
Less:							
Miscellaneous Energy Deliveries[2][5]	257	0	–	–	–	68	136
Losses and System Uses[2]	2,791	3,031	4,479	3,879	3,507	3,420	3,668
On-System Sales[2]	12,250	11,759	22,495	21,833	22,550	22,801	22,954
Sales of Energy[2]							
Residential	4,030	4,362	7,707	7,218	7,303	7,258	7,285
Commercial and Industrial	7,300	6,972	13,220	14,030	14,661	15,210	15,311
All Other	1,273	1,041	2,087	1,050	626	532	1,426
Total	12,603	12,375	23,014	22,298	22,590	23,000	24,022
Number of Customers – (Average, in thousands):							
Residential	1,424	1,407	1,414	1,405	1,397	1,385	1,378
Commercial and Industrial	127	126	126	126	126	124	123
All Other	7	7	7	7	7	7	7
Total	1,558	1,540	1,547	1,538	1,529	1,516	1,508

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

(1) Data for the six-month period ended December 31, 2021 is preliminary and subject to change. Results for the first six months of Fiscal Year 2021-22 may not be indicative of results for full Fiscal Year 2021-22. See "FACTORS AFFECTING THE DEPARTMENT AND THE UTILITY INDUSTRY – COVID-19 Pandemic."

(2) Thousands of MWhs.

(3) 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.

(4) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.

(5) Deliveries include transmission loss energy paybacks and control area inadvertent interchange.

Financial Information

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

POWER SYSTEM
SELECTED FINANCIAL INFORMATION
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31[1]		Fiscal Year Ended June 30[2]				
	2021	**2020**	**2021**	**2020**	**2019**	**2018**	**2017**
Operating Revenues							
Residential	$827,175	$835,726	$1,614,033	$1,360,648	$1,376,341	$1,265,713	$1,179,514
Commercial and Industrial	1,333,471	1,205,539	2,492,138	2,372,533	2,560,098	2,429,323	2,331,599
Sales for resale[3]	153,162	120,891	186,706	61,455	111,542	91,351	88,099
Other[4]	(22,381)	(19,796)	(24,399)	12,655	22,949	17,834	98,712[9]
Total Operating Revenues	$2,291,427	$2,142,358	$4,268,478	$3,807,291	$4,070,930	$3,804,221	$3,697,924
Average Revenue per kWh Sold[5]							
Residential	0.205	0.192	0.209	0.189	0.188	0.174	0.162
Commercial and Industrial	0.183	0.173	0.189	0.169	0.175	0.160	0.152
Average Annual Residential Usage[6]	3	3	5	5	5	5	5
Operating income	$395,277	$367,280	$ 744,139	$ 363,981	$ 512,310	$ 725,259	$ 611,726
As % of revenues	17.3%	17.1%	17.4%	9.6%	12.6%	19.1%	16.5%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[7][10]	$269,186	$223,919	$ 633,942	$ 320,065	$ 459,503	$ (141,192)	$ 441,293
Adjusted Change in Net Position, including Power Transfer and accounting change [8][10]	$44,171	$5,564	$ 415,587	$ 90,152	$ 226,946	$ (383,040)	$ 176,866

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

(1) Data for the six-month period ended December 31, 2021 is preliminary and subject to change. Results for the first six months of Fiscal Year 2021-22 may not be indicative of results for full Fiscal Year 2021-22. See "FACTORS AFFECTING THE DEPARTMENT AND THE UTILITY INDUSTRY – COVID-19 Pandemic."

(2) Derived from the Power System Financial Statements (except for usage statistics).

(3) Includes sales of power and transmission services to other utilities.

(4) Net of Uncollectible Accounts.

(5) 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.

(6) MWh use per residential customer.

(7) Represents change in net position before Power Transfer and after cumulative effect of change in accounting for OPEB charged to net position July 1, 2017, totaling $661,230 (in thousands).

(8) Represents change in net position after Power Transfer and cumulative effect of change in accounting for OPEB charged to net position July 1, 2017, totaling $661,230 (in thousands).

(9) This amount includes revenue recognized due to the reduction of the incremental rate stabilization account balance.

(10) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements. Adjustments reflect the impact of the implementation of new accounting standards, particularly GASB No. 75, which resulted in the recording of certain OPEB liabilities and a corresponding reduction in net position.

POWER SYSTEM
SUMMARY OF REVENUES, EXPENSES AND DEBT SERVICE COVERAGE
(Dollars in Thousands)
(Unaudited)

	Six Month Period Ended December 31[1]		Fiscal Year Ended June 30[2]				
	2021	**2020**	**2021**	**2020**	**2019**	**2018**	**2017**
Operating Revenues							
Sales of Electric Energy:							
Residential	$827,175	$835,726	$1,614,033	$1,360,648	$1,376,341	$1,265,713	$1,179,514
Commercial and industrial	1,333,471	1,205,539	2,492,138	2,372,533	2,560,098	2,429,323	2,331,599
Sales for resale	153,162	120,891	186,706	61,455	111,542	91,351	88,099
Other[3]	(22,381)	(19,796)	(24,399)	12,655	22,949	17,834	98,712[6]
Total Operating Revenues	$2,291,427	$2,142,358	$4,268,478	$3,807,291	$4,070,930	$3,804,221	$3,697,924
Operating Expenses							
Production:							
Fuel for Generation	$176,734	$139,903	$ 228,697	$ 207,043	$ 296,506	$ 268,610	$ 292,557
Purchased Power	658,019	627,029	1,301,394	1,242,068	1,264,133	1,143,535	1,165,303
Energy Cost	834,753	766,932	1,530,091	1,449,111	1,560,639	1,412,145	1,457,860
Maintenance and Other Operating Expenses	704,806	677,449	1,323,158	1,364,303	1,412,750	1,112,463	1,107,118
Adjusted Operating Expenses[4][7]	$1,539,559	$1,444,381	$2,853,249	$2,813,414	$2,973,389	$2,524,608	$2,564,978
Adjusted Operating Income[4][7]	$ 751,868	$ 697,977	$1,415,229	$ 993,877	$1,097,541	$1,279,613	$1,132,946
Other non-operating income and expenses, net	32,468	6,566	145,303	268,502	239,211	92,659	114,040
Contributions in aid of construction	19,748	29,645	103,459	57,692	58,373	42,460	32,177
Adjusted Change in Net Position[5][7]	$ 804,084	$ 734,188	$1,663,991	$1,320,071	$1,395,125	$1,414,732	$1,279,163
Debt Service							
Adjusted Interest[7][8]	230,566	229,784	459,413	454,074	426,577	414,722	384,899
Principal	187,683	179,035	179,405	171,925	153,664	131,756	153,915
Total debt service	$ 418,249	$ 408,819	$ 638,818	$ 625,999	$ 580,241	$ 546,478	$ 538,814
Debt Service Coverage Ratio	N/A	N/A	2.60	2.11	2.40	2.59	2.37
Depreciation, amortization and accretion	$ 356,591	$ 330,697	$ 671,090	$ 629,896	$ 585,231	$ 554,354	$ 521,220
Transfers to the Reserve Fund of the City	$ 225,015	$ 218,355	$ 218,355	$ 229,913	$ 232,557	$ 241,848	$ 264,427

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

(1) Data for the six-month period ended December 31, 2021 is preliminary and subject to change. Results for the first six months of Fiscal Year 2021-22 may not be indicative of results for full Fiscal Year 2021-22. See "FACTORS AFFECTING THE DEPARTMENT AND THE UTILITY INDUSTRY – COVID-19 Pandemic."

(2) Derived from the Power System Financial Statements.

(3) Net of Uncollectible Accounts.

(4) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.

(5) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.

(6) This amount includes revenue recognized due to the reduction of the incremental rate stabilization account balance.

(7) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements, as provided in footnotes 3, 4 and 7 in this table.

(8) Interest expense excluding amortization of debt premium.

Indebtedness

As of February 3, 2022, approximately $10.62 billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $9.63 billion in principal amount is fixed-rate bonds and approximately $992 million in principal amount is variable-rate bonds. In connection with the Department's five-year capital improvements to the Power System, the Department anticipates that it will issue approximately $6.31 billion of debt through June 30, 2026 payable from the Power Revenue Fund. See "THE POWER SYSTEM – Projected Capital Improvements" and "Note (9) Long-Term Debt" of the Department's Power System Financial Statements.

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"). The 2014 Series A Bonds are currently held by Bank of America, N.A. pursuant to a Continuing Covenant Agreement, dated as of May 1, 2020 (the "Continuing Covenant Agreement"), between the Department and Bank of America, N.A. The 2014 Series A Bonds are Variable Rate Indebtedness, maturing on July 1, 2038 in a SIFMA-based index period ending on May 2, 2025. 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 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.

On December 14, 2018, the Department entered into a revolving credit agreement (the "Wells RCA") with Wells Fargo Bank, National Association ("Wells Fargo") in a principal amount not-to-exceed $300 million outstanding at any one time; provided that the Department can request that Wells Fargo increase the available commitment under the Wells RCA by an additional $200 million, with approval of such increase being at the sole discretion of Wells Fargo. As of February 3, 2022, the Department has no obligations outstanding under the Wells RCA payable from the Power Revenue Fund. Under the Wells RCA, which expires on December 13, 2023, amounts due may be paid by the Department at any time at its option and in the event of default under the Wells RCA, amounts outstanding would be due immediately. The Department expects to pay principal amounts due under the Wells RCA from proceeds of subsequent borrowings or from reserves available to the Power System. Amounts borrowed under the Wells RCA payable from the Power Revenue Fund are considered Parity Obligations under the Master Resolution. The Department does not believe that its obligations with respect to the Wells RCA will result in a default under the Department's other Parity Obligations.

For more information about the Department's variable rate bonds, including their associated liquidity facilities, see "Note (10) Variable Rate Bonds" of the Department's Power System Financial Statements.

In addition, as of February 1, 2022, 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 $1.04 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 February 1, 2022. 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.

The Department is scheduled to issue its $360,000,000 Power System Revenue Bonds, 2022 Series B on April 20, 2022.

Take-or-Pay Obligations

The Department entered into the IPP Contract and the IPP Excess Power Sales Agreement to purchase up to a 66.79% share 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 and the agreements with respect to the SCPPA projects (other than with respect to projects in which the Department is the sole participant) contain certain step-up 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 February 1, 2022, for each of the foregoing projects are shown in the following table:

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POWER SYSTEM
TAKE-OR-PAY OBLIGATIONS FOR BONDS
As of February 1, 2022
(Dollars in Millions)
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt[7]
Intermountain Power Agency			
IPP	$ 193[1][3]	48.62%[2]	$ 94[3]
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	20	100.00[4]	20
Mead-Phoenix Transmission Project	16	100.00[4]	16
Linden Wind Energy Project	91	100.00[5]	91
Milford Wind Corridor Phase I Project	96	92.50[6]	89
Milford Wind Corridor Phase II Project	79	100.00[5]	79
Southern Transmission System	239	59.50[6]	142
Windy Point Project	262	100.00[5]	262
Apex Power Project	251	100.00[6]	251
Total	$1,247		$1,044

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

(1) Includes $88.5 million draw on a flexible drawdown bond.

(2) Includes the Department's obligations under the IPP Contract (48.617%) but does not include the Department's obligations under the IPP Excess Power Sales Agreement 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 $100.9 million as of February 1, 2022, due to the Department's prepayment of a portion of its share of IPA's debt.

(4) The bonds remaining outstanding relate to the additional interest acquired by SCPPA solely for the benefit of the Department.

(5) Equals the Department's share of SCPPA's and the City of Glendale's entitlements. See "THE POWER SYSTEM – Renewable Power Initiatives."

(6) Equals the Department's share of SCPPA's entitlement.

(7) In addition to outstanding principal, the Department is obligated to pay its share of interest on outstanding debt and annual operating and maintenance costs. See Note (5) to the Department's Power System Financial Statements.

FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY

The following regulatory programs affect the Department and the electric utility industry and should be considered when evaluating the Department. The Department cannot predict at this time whether any additional legislation or rules will be enacted which will affect the Power System's operations, and if such laws or rules are enacted, what the costs to the Department might be in the future because of such action. See "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES," "ELECTRIC RATES," "THE POWER SYSTEM – Projected Capital Improvements," "OPERATING AND FINANCIAL INFORMATION" and the Department's Power System Financial Statements for additional information relating to the Department.

California Climate Change Policy Developments

State regulatory agencies such as CARB and the CEC are pursuing a number of regulatory programs designed to reduce GHG emissions and encourage or mandate renewable energy generation. The following is a summary of certain programs. See also "Environmental Regulation and Permitting Factors" below.

GHG Regulations. In September 2006, then-Governor Schwarzenegger signed into law the Global Warming Solutions Act. This law requires a cut in GHG emissions from within the State by 2020 in order to reduce such emissions back to 1990 levels, which represents a reduction of approximately 25% Statewide. In September 2016, then-Governor Brown signed into law an amendment to the Global Warming Solutions Act that requires a cut in GHG emissions from within the State by 2030 in order to reduce such emissions to 40% below 1990 levels.

CARB implemented the Global Warming Solutions Act through regulations (the "Cap-and-Trade Regulations") that imposed aggregate emissions limitations on the electricity generation industry in the State and allocates the aggregate emissions limit through the distribution of allowances, or emission credits.

The Cap-and-Trade Regulations require all regulated entities, including the Department, to obtain and submit to CARB allowances and/or offsets with respect to GHG emissions relating to its State generation activities, as well as for imported electricity from dedicated out-of-state resources such as the IPP. In addition, the Department may indirectly bear compliance costs for independent generators that must purchase allowances for their generation.

The Department, like other electric utilities, receives administrative allocations of allowances for some of their expected GHG emissions. Entities that emit GHGs at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or from other covered entities with surplus allowances. The Department believes that, if its administratively-granted free allowances were not sufficient to authorize all of the Department's generation and purchases of electricity from fossil fuel-fired sources, the Department could obtain any other required allowances by participating in the CARB auctions or the secondary market. The Department also believes that the costs of compliance with the Cap-and-Trade Regulations will be substantially covered by existing rate adjustments and anticipated rate increases through 2030.

In July 2017, CARB adopted amendments to the Cap-and-Trade Regulations, which included revised allowance allocations to electrical distribution utilities such as the Department from 2021 to 2030. The Power System is expected to be able to comply with the amendments with minimal impact to its finances or operations in connection with the implementation of the Power System's resource plan.

In July 2017, then-Governor Brown signed into law AB 398 to extend the state's Cap-and-Trade Regulations from 2021 to 2030. The bill cleared both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, CARB is directed to address the following: establish a price ceiling, offer nontradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance overallocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. AB 398 was passed in conjunction with two companion bills: AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities, and Assembly Constitutional Amendment No. 1 (ACA-1), which establishes the Greenhouse Gas Reduction Reserve Fund. In December 2018, CARB approved amendments to the Cap-and-Trade Regulations to make the cap-and-trade program consistent with AB 398 requirements. The Department does not expect such amendments to have a material adverse effect on the operations or financial condition of the Power System.

GHG Emissions Performance Standard and Financial Commitment Limits. Pursuant to SB 1368 (Chapter 598, Statutes of 2006), the CEC adopted a GHG emissions performance standard ("EPS") for electric generating facilities of 1,100 pounds of CO2 per MWh for "covered procurements" by POUs, such as the Department. SB 1368 also prohibits POUs from making any "long-term financial commitment" in connection with "baseload generation" that does not satisfy the EPS. Generally, a "long term financial

commitment" is any new or renewed power purchase agreement with a term of five years or more, the purchase of an interest in a new power plant or any investment, other than routine maintenance, in an existing power plant that is designed and intended to extend the life of the plant by more than five years or results in an increase of 50 MWs or more in its rated capacity. "Baseload generation" means a power plant that is intended to operate at an annualized capacity factor of 60 percent or more.

California Renewable Portfolio Standard. The State's legislature and executive branch have been active in promoting increasingly stringent renewable energy procurement requirements since 2002. Early efforts established a standard of 20% of renewable electricity generation by 2017. Since then, both legislative and executive branch initiatives have raised that standard in multiple phases.

On April 12, 2011, then-Governor Brown signed into law the California Renewable Energy Resources Act, or SBX 1-2. SBX 1-2 established procurement targets for three compliance periods to be implemented by the procurement plan: 20% of the utility's retail sales were to be procured from eligible renewable energy resources by December 31, 2013; 25% by December 31, 2016; and 33% by December 31, 2020.

In October 2015, then-Governor Brown signed into law SB 350, which requires the Department to make reasonable progress each year to ensure it achieves 40% of retail sales from eligible renewable energy resources by December 31, 2024, 45% of retail sales from eligible renewable energy resources by December 31, 2027, and 50% of retail sales from eligible renewable energy resources by December 31, 2030.

In September 2018, then-Governor Brown signed into law SB 100, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as the Department, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of the State that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to State end-use customers by December 31, 2045. Defining resources that constitute a "zero-carbon resources" will be subject to further regulatory proceedings of the CEC and CARB. The author of SB 100, Senator Kevin De León, signed a letter that was filed on August 31, 2018, indicating that the author's intent was to include existing resources that do not produce GHG emissions, such as large hydro and nuclear resources, besides renewables, in the definition of a "zero-carbon resources." The CEC has adopted updates to the RPS Enforcement Procedures for Publicly Owned Utilities which incorporate requirements set forth in SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350 pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of RPS procurement must be from contracts of 10 years or more in duration or in ownership or ownership agreements. The updated regulations were adopted by the CEC on December 22, 2020 and approved by the California Office of Administrative Law with an effective date of July 12, 2021.

See "THE POWER SYSTEM – Renewable Power Initiatives" and "– Projected Capital Improvements" for a description of the Department's existing and potential renewable energy projects.

Biomass Legislation. In September 2016, then-Governor Brown signed into law SB 859 that, among other things, requires certain electric utilities to enter into five-year contracts for at least 125 MWs of biomass capacity with facilities that generate energy from feedstock harvested from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. In order to comply with these provisions of SB 859, the Department is required to enter into contracts for 14.3 MWs of biomass capacity, of which it has already obtained 8.9 MWs (however, such obtained capacity may be affected by the bankruptcy of the project's contractor, ARP-Loyalton). Due to the specific requirements of the law, the available facilities

satisfying the requirements of the law are limited. The Department, SCPPA and the other POUs have satisfied the SB 859 requirements with the ARP-Loyalton contract and a contract for 5.4 MWs of capacity with Roseburg Forrest Products Co., in Weed, California. See "THE POWER SYSTEM – Renewable Power Initiatives – *Biomass Development*."

Energy Storage Legislation. On October 14, 2017, then-Governor Brown signed into law SB 801, which required the Department, by June 1, 2018, to determine the cost-effectiveness and feasibility of deploying a minimum aggregate total of 100 MWs of cost-effective energy storage solutions to help address the Los Angeles basin's electrical system operational limitations resulting from reduced gas deliverability from the Aliso Canyon natural gas storage facility. Department staff performed analysis and found that a 100 MW battery energy storage system paired with solar generation at the grid will be cost effective by 2022. See "THE POWER SYSTEM – Renewable Power Initiatives – *Energy Storage Development*." To comply with such legislation, the Department has entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. See "THE POWER SYSTEM – Renewable Power Initiatives – *Solar Power Programs*."

Biomethane Procurement. In September 2018, then-Governor Brown signed into law SB 1440, which requires the CPUC and CARB to consider adopting biomethane targets or goals applicable to gas service providers. In December 2019, the CPUC held a workshop to consider SB 1440 implementation and renewable gas procurement as a cost-effective strategy to reduce methane emissions. Earlier in 2019, the CPUC held several workshops to discuss standards required to interconnect and inject renewable methane and hydrogen projects into the natural gas pipeline system. In January 2020, the CPUC held a working group meeting to discuss current knowledge of hydrogen blending and development of a standard for hydrogen injection. In May 2020, the CPUC held a workshop to discuss the proposed renewable natural gas interconnection and operating agreements that were developed and submitted by the joint gas utilities. These agreements will enable receipt of renewable gas produced by dairies and other sources into the utility pipelines, which will reduce methane emissions and the carbon intensity of natural gas consumed in the State. The Department will continue to monitor this proceeding.

Renewable Energy Policy Development. In August 2018, the CEC adopted the policy "Toward A Clean Energy Future, 2018 Integrated Energy Policy Report Update" (the "2018 IEPR"). The 2018 IEPR is composed of two volumes. The first volume is a high-level summary of the energy policies the State has implemented in recent years. This high-level summary includes (i) the State's participation in an international pact to reduce emissions and increase renewable electricity procurement to 33% by 2020 and 50% by 2030; (ii) continued support for incentives or mandates for more homes and business to install rooftop solar; (iii) an executive order calling for at least 5 million zero-emission vehicles on the State's roads by 2030 and an extensive expansion of charging and refueling infrastructure; and (iv) continued support for the development and implementation of an energy efficient program in existing buildings. The second volume provides updated analysis of issues raised in previous Integrated Energy Policy Reports, including "advancing then-Governor Brown's call to expand state adaptation activities through Executive Order B-30-15, with the goal of making the consideration of climate change a routine part of planning," as well as, "enhancing the resiliency of the electricity system while integrating increasing amounts of renewable energy." See "– Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board*" below.

Legislation and Court Action Relating to Wildfires. In September 2016, then-Governor Brown signed into law SB 1028, which requires each POU, including the Department, each IOU and each electric cooperative in the State to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. Effective January 1, 2017, SB 1028 requires the governing board of each POU to make an initial determination of whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on

historical fires and local conditions. POU governing boards must independently make this determination based on all relevant information, including the CPUC's Fire Threat Map which was adopted by the CPUC in January 2018. On September 5, 2018, the Board determined that the Power System's overhead electrical lines and equipment do not pose a significant risk of causing a catastrophic wildfire. Prior to the enactment of SB 1028, the Department has had an active fire prevention plan since 2008, which includes construction standards, a vegetation management program, and an inspection and maintenance program.

SB 901, which was signed into law in September 2018, amends certain provisions of SB 1028. SB 901 requires, among other things, POUs, such as the Department, to prepare before January 1, 2020 and annually thereafter, a wildfire mitigation plan. SB 901 requires the POU to contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator is to be made available to the public and presented at a public meeting of the POU's governing board. The Department updates its wildfire mitigation plan on an annual basis, with comprehensive revisions and independent evaluator reviews occurring every three years. The Department most recently presented its wildfire mitigation plan and the independent evaluator's assessment to the Board on January 12, 2021.

In 2017, the CPUC adopted a work plan for the development and adoption of the CPUC Fire-Threat Map. On the CPUC Fire-Threat Map, any area in a Tier 2 fire-threat area is depicted as an "elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires" and any area in a Tier 3 fire-threat area is depicted as an "extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." Based on the wildfire mitigation plan dated April 17, 2020, approximately 14.1% of the Power System's overhead distribution power lines fall within a Tier 2 area and approximately 0.5% of the Power System's overhead distribution power lines fall within a Tier 3 area. The Department has not modeled a total destruction scenario in Tier 2 and Tier 3 areas of its service territory because such areas represent a small portion of the Power System's service territory; but the Department believes that based on the low density of the property in the applicable Tier 2 and Tier 3 areas, the potential property damage is expected to be relatively low. In these applicable Tier 2 and Tier 3 areas, the Department continues to replace wooden pole assets with alternative material poles, install covered conductors where feasible, equip poles for high wind load in order to resist fire damage, and employ a robust vegetation management program to further mitigate wildfire risk exposure.

In April 2019, Governor Newsom released a report of findings of an appointed working group examining the State's wildfires and associated liability. The report provided recommendations for changes in State fire prevention and response and suggested an exploration of a new model for paying wildfire-related costs. AB 1054, which was signed into law by Governor Newsom in July 2019, codifies some of the recommendations of such report. AB 1054 requires POUs to submit their wildfire mitigation plans for annual review to a newly created California Wildfire Safety Advisory Board, with comprehensive revisions submitted every three years. The Department submitted its wildfire mitigation plan to the California Wildfire Safety Advisory Board on June 5, 2020. The California Wildfire Safety Advisory Board published its draft guidance advisory opinion for Publicly Owned Utilities on November 13, 2020 and found the Department's wildfire mitigation plan to be comprehensive with clear descriptions of its relevant programs. The Department submitted incremental updates to the Wildfire Safety Board that were due by July 1, 2021. The California Wildfire Safety Advisory Board published its recommendations on the 2022 Wildfire Mitigation Plan Guidelines, Performance Metrics, and Safety Culture Assessment on June 28, 2021. The Department is required to provide its next comprehensive updates to the Department's wildfire mitigation plan for Wildfire Safety Advisory Board submittal by July 1, 2022.

AB 1054 also establishes a new wildfire fund for IOUs to pay for eligible claims arising from future covered wildfires. Participation in the wildfire fund is exclusive to IOUs. Governor Newsom's working group's report also identified the concept of changing the strict liability standard under the State's inverse

condemnation law to a fault-based liability standard. The Department continues to monitor State level legislative activity for potential updates regarding strict liability. It is not yet known what impact any potential actions resulting from this report may have on the finances or operations of the Power System.

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

See "LITIGATION – Wildfire Litigation" for information about current litigation regarding wildfires and "THE DEPARTMENT – Insurance" for information about the Department's current insurance coverage for wildfires.

Environmental Regulation and Permitting Factors

General. Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions. The Department's four Los Angeles Basin power plants are subject to the Regional Clean Air Incentives Market ("RECLAIM") NOx regulations adopted by the SCAQMD. In accordance with these regulations, SCAQMD established annual NOx allocations for stationary source facilities based on historical emissions with a declining emissions cap. These allocations are in the form of RECLAIM trading credits ("RTCs"). Facilities can comply with RECLAIM by purchasing RTCs from the RECLAIM market, installing emission controls, and/or reducing operations. The Department has installed emission control equipment at its power plants to reduce NOx emissions. The Los Angeles Basin Stations are all equipped with emission control equipment. As a result of the installation of NOx control equipment and the modernization of existing electric generating units, the Department has had sufficient RTCs to meet its native load requirements for normal operations under the NOx RECLAIM regulation.

In March 2017, the SCAQMD adopted the 2016 Air Quality Management Plan and included a control measure to achieve an additional five tons per day NOx reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology ("BARCT") as soon as feasible.

In July 2017, then-Governor Brown approved AB 617 which addresses criteria pollutants (including NOx) and toxic air contaminants at stationary sources. RECLAIM facilities are subject to the BARCT requirements of AB 617.

The Department has been participating in RECLAIM working group meetings related to the transition from the market-based RECLAIM program to a command-and-control regulatory structure. The RECLAIM program was originally scheduled to end on December 31, 2023 but is now expected to extend past 2024 after the EPA's approval of the State Implementation Plan and the resolution of outstanding issues with the New Source Review ("NSR") Program. The RECLAIM working group has been having discussions regarding the NSR Program and its applicability to major source modifications after exiting the RECLAIM Program. SCAQMD is currently reviewing the current NSR process and is considering comments from stakeholders including the Department regarding SCAQMD's proposed changes to the NSR process. The Los Angeles Basin Stations will transition from RECLAIM to a source-specific NOx rule for electric generating units that will include NOx limits reflecting BARCT. SCAQMD Rule 1135, the "command-and-control" rule for electric generating units, was adopted on November 2, 2018. Instead of receiving an annual allocation of emission credits, electric generating units will be required to meet a NOx emission limit. The NOx emission limits for simple cycle gas turbines is 2.5 parts per million (ppm) over a 60-minute rolling average. To comply with the new NOx limits, the existing selective catalytic reduction equipment for the Department's simple cycle combustion turbines at the Harbor Generating Station and the Valley Generating Station are being tuned to meet the 2.5 ppm limit. The remaining electric generating units either already meeting the NOx limits or are exempt from the rule. The Department does not expect the modifications to have a material adverse effect on the operations or financial condition of the Power System. The upgrades are expected to be completed well before the Rule 1135 compliance date of December 31, 2023. SCAQMD is hosting additional working group meetings for Rule 1135 beginning in May 2021 to amend the rule to include additional startup and shutdown provisions and ammonia slip limits.

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

On October 23, 2015, the EPA, under the Obama Administration, published the Clean Power Plan and final regulations for (1) carbon pollution standards for new, modified, and reconstructed power plans, and (2) carbon pollution emission guidelines for existing electricity utility generating units. The total national emissions reduction goal under the Clean Power Plan targets an average of a 32 percent reduction from 2005 levels by 2030, with incremental interim goals for the years 2022 through 2029. The Clean Power Plan would have allowed states multiple options for measuring reductions and different established reduction goals depending upon the regulatory program set forth in the state plan. On July 8, 2019, the EPA issued final new regulations entitled the "Affordable Clean Energy Rule" to replace the Clean Power Plan. On January 19, 2021, upon a challenge by a number of environmental advocates, state and municipal attorneys, and a coalition that included the Department, the D.C. Circuit vacated the Affordable Clean Energy Rule. Moreover, on October 29, 2021, the U.S. Supreme Court granted certiorari to hear challenges

to EPA's authority to regulate GHGs emissions from power plants. The Department cannot predict the timing or content of any new regulations that may be proposed to replace the Affordable Clean Energy Rule. At this time, the Department does not expect any such regulations to have material effects on its operations.

See also, "THE POWER SYSTEM — General," "—Department-Owned Generating Units," "—Jointly Owned Generating Units and Contracted Capacity Rights in Generating Units," "—Projected Capital Improvements," "—Energy Efficiency" and "—Renewable Power Initiatives."

Air Quality – Mercury. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants (**"**HAPs**"**), including mercury. On February 16, 2012, EPA finalized a rule called the Mercury and Air Toxics Standards (**"**MATS**"**) to reduce emissions of toxic air pollutants, including mercury, from coal- and oil-fired electric generating units, and subsequently amended the rule in 2013 and 2014. The MATS rule set technology-based emission limitation standards for mercury and other toxic air pollutants, based upon reductions available through the use of **"**maximum achievable control technology**"** at coal- and oil-fired electric generating units. The rule has minimal impact to IPP, the one remaining coal-fired plant that is a source of energy for the Department. IPP did not have to install control technology and EPA has deemed the IPP units as low-emitting units. IPP is subject to periodic testing, work practice standards and recordkeeping requirements.

In order to comply with the MATS rule, IPP replaced the ignitors to decelerate the destruction of baghouses, the upfront cost of which was $5.5 million. The cost of compliance with work practice standards are minimal, approximately $50,000 per year. IPP will not be required to install additional control technology to reduce its HAPs. However, the Department continues to examine other possible options to meet the requirements in the most effective manner. IPP already utilizes wet scrubbers and fabric filters that significantly reduce HAPs. The State of Utah adopted minimum performance criteria for existing electric generating units and offset requirements for potential increases in mercury emissions from new or modified electric generating units. Utah's minimum performance criteria include a rule, effective January 1, 2012, that coal-fired power plants, such as IPP, meet a mercury emissions limit of 0.00000065 lb/MMBtu or have at least a 90% mercury removal efficiency. IPP complies with the Utah mercury standard.

SCAQMD Air Quality Management Plan. The SCAQMD periodically prepares an overall plan, known as an Air Quality Management Plan (the "AQMP"), which include control measures to meet federal air quality standards and incorporate the latest technical planning information. In March 2017, SCAQMD adopted its 2016 AQMP, which is a regional and multi-agency effort. The SCAQMD held stakeholder working group meetings in connection with its development of rules and rule amendments to implement the control measures included in the 2016 AQMP, and submitted their control measure plan to EPA in December 2019. The Department participated in working group meetings related to control measures that may impact its operations. SCAQMD is in the early stages of the 2022 AQMP process, and is looking for a 45% reduction in NOx emissions through this plan. The Department will continue to monitor development of the 2022 AQMP for any emission reduction measures that will affect power plants or fleets. At this time, AQMP working groups are focusing on charging and fueling infrastructure needs and other mobile source categories.

Water Quality – Cooling Water Process.

General. A cooling process is necessary for nearly every type of steam turbine electrical generating station. 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. 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. A final regulation implementing Section 316(b) of the Clean Water Act ("Rule 316(b)") addresses the impacts of water intake by once-through-cooling systems. Rule 316(b) affects intake structures for power generating facilities that withdraw more than two million gallons per day for cooling purposes. The Department has determined it will comply with impingement mortality ("IM") and entrainment mortality ("EM") by replacing once-through-cooling with other technology by the deadlines of 2024 and 2029 negotiated with the SWRCB.

State Water Resources Control Board. The SWRCB established a separate statewide policy with respect to the Clean Water Act Section 316(b) in 2010 published as Section 2922 of Title 23 of the California Code of Regulations ("Regulation Section 2922"). The new regulation generally requires all facilities subject to the Clean Water Act Section 316(b) to either use closed cycle cooling or flow reduction commensurate to that of wet closed cycle. 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 Regulation Section 2922.

On July 19, 2011, the SWRCB 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 Department expects to be fully compliant with this amended schedule; however, on February 12, 2019, Los Angeles Mayor Eric Garcetti announced that the Department would abandon plans to repower once-through-cooling gas-fired power plants, and instead will focus on energy storage and other clean energy technology. Depending on grid reliability, the Department may request the alignment of all ocean water cooling deadlines to 2029 with the SWRCB, shift focus from repowering Scattergood Generating Station to clean energy alternatives, issue requests for information for new energy storage, local solar, energy efficiency, and demand response, convene a transmission working group, and work with neighboring utilities to maximize resources.

Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station. The SWRCB'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 during the next permit renewal. 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 concluded that the estuary classification does not reflect current site conditions with the operation of the existing power plants. However, the LARWQCB stated that for regulatory purposes, the Lower San Gabriel River would likely represent an estuary. With this designation, the Haynes Generating Station would be unable to comply with the California Thermal Plan and other permit conditions 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. The LARWQCB has recognized the need to continue utilizing once-through cooling at the Haynes Generating Station through 2029 for electric grid reliability and is currently working with the Department on a solution for all discharge issues associated with the estuary designation, which could include the issuance of a variance.

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, as well as State statutes, impose strict liability for cleanup costs upon those who generate or dispose of hazardous substances and hazardous wastes. The Department's past disposal practices may result in Superfund liability as previously approved disposal methods or sites become candidates for Superfund classification. In addition, under these statutes, the Department may be held liable for cleanup activities on property that it owns and operates, even if the conditions requiring cleanup existed before the Department's occupancy of a site. As a result, the Department may incur substantial, but presently unknown, costs as a participant in the cleanup of sites contaminated with hazardous substances or wastes.

Coal Combustion Residuals. In April 2015, the EPA promulgated the final coal combustion residuals ("CCR") rule, which regulates the disposal and management of CCRs as non-hazardous under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The final CCR rule became effective in October 2015.

Under the CCR rule, existing impoundments for managing CCR must either cease accepting CCR materials as of the rule's effective date, or implement a variety of measures to ensure that such facilities will not result in releases to the environment. One such requirement is that all such facilities be retrofitted with liners that are intended to prevent the migration to groundwater of contaminants found in CCR. In addition, the rule requires monitoring of groundwater to determine whether releases have occurred, and to contain or clean up any such releases that are discovered.

The IPP utilizes impoundments (ponds and landfills) for the management of CCR that are subject to the CCR rule. The IPP has met all interim compliance requirements for the new CCR rule including: setting up a public website and posting CCR operating records, developing new groundwater monitoring wells and sampling plans, beginning to sample groundwater wells quarterly, and developing and implementing a fugitive dust monitoring plan.

The Department believes that the IPP's CCR management facilities may not meet the design criteria required for surface impoundments and that releases of certain contaminants have occurred from the current, unlined impoundments. The Department understands that IPA has made notification that IPP will cease operations of the coal-fired boilers and switch to another fuel source for generation by 2028.

The Department has estimated the IPP's total cost of compliance with the final CCR rule to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period commencing in 2019 and ending between approximately 2025 and 2028 (except for long-term monitoring and maintenance, which would last approximately 30 years after closure). Of this total cost, the Power System would be responsible for a percentage equal to its total use of energy produced by IPP. For more information about IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

In November 2019, the EPA proposed revisions (Part A) to the CCR rule. The proposed revisions focus on closure requirements for impoundments and landfills. IPA is opting to comply with the alternate closure requirement as currently described in the current CCR rule. The proposed revisions include additional requirements to get approval of the EPA or the state to close impoundments in accordance with alternate closure procedures. There is also a new requirement to prepare a plan to mitigate potential risk to

human health and environmental from CCR surface impoundments. The Part A revisions were finalized and published in the Federal Register in August 2020. IPP has submitted a request to the EPA demonstrating that they meet the alternate closure procedures as described in the regulations. IPP is awaiting EPA review and approval which was initially expected to be received by April 2021, however the EPA has placed all reviews on hold for coal-fired generating units.

In February 2020, the EPA proposed a federal CCR permit program. Currently, the CCR rule is self-implementing and is enforced primarily though citizen suits which are decided in federal district courts. This program will not change the provisions of the regulations but the EPA will be able to review, approve, issue, and enforce the CCR regulations through the permit program.

In March 2020, the EPA proposed more revisions (Part B) to the CCR rule including provisions to demonstrate equivalent alternate liners, using CCR for closing impoundments, and completion of closure by removal during post closure care period. The proposed revisions do not impact IPA's plan to follow alternate closure requirements.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects resulting from exposure to electric and magnetic fields created by high voltage transmission and distribution equipment. Additional studies are being conducted to determine the relationship between electric and magnetic fields and certain adverse health effects, if any. At this time, it is not possible to predict the extent of the costs and other impacts, if any, which the electric and magnetic fields concerns may have on electric utilities, including the Department.

For additional information regarding environmental matters, see "THE POWER SYSTEM—Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Hoover Power Plant – Environmental Considerations*" and " – *Palo Verde Nuclear Generating Station – Nuclear Waste Storage and Disposal*."

Energy Regulatory Factors

Developments in the California Energy Market. In the late 1990s, the State restructured its electricity market so that regulated retail suppliers were required to purchase their customers' supply needs through a centralized, wholesale market. In the centralized market, an administrator collected sellers' price bids and purchasers' estimates of demand. The administrator then determined the price for the most costly unit that was needed to meet demand, and all transactions occurred at that price. The wholesale market was structured as a "spot" market in which prices were set and purchases were made on a short-term basis shortly before supply was needed. The State also capped the price at which regulated retail suppliers could sell electricity to their customers. During portions of 2000 and 2001, wholesale market prices in the State became highly volatile and, for sustained periods, significantly exceeded the capped retail prices. Demand did not decline in response to high wholesale prices because retail prices were capped. This situation resulted in the deterioration of the creditworthiness of two large, retail suppliers, Pacific Gas & Electric Company ("PG&E") and Edison, and PG&E eventually declared bankruptcy. Certain other marketers, power suppliers and power plant developers experienced downgrades of their credit ratings. PG&E emerged from bankruptcy on April 12, 2004. Subsequently, PG&E reentered bankruptcy in 2019 which it attributed to the potential magnitude of its liabilities related to wildfires in Northern California. PG&E emerged from that bankruptcy on July 1, 2020. The Department has no long-term contracts currently in place for the purchase of energy, energy-related commodities, or natural gas from PG&E. To date, the Department has not experienced any material adverse impacts as a result of the PG&E bankruptcy filing. There remain a number of uncertainties surrounding the PG&E Entities' emergence from bankruptcy. As a result, the Department is unable to predict the full effects of the PG&E Entities' bankruptcy proceedings on the Power System or the State electric markets at this time. See "FACTORS AFFECTING THE

DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

The volatility in wholesale prices that the State experienced in 2000 and 2001 was due to a number of factors, including flaws in the structure of the wholesale market and unlawful manipulation of the wholesale market. As discussed below, the wholesale market in the State has since been redesigned, and Congress has established mechanics for policing wholesale markets.

Volatility in electricity prices in the State may nevertheless return due to a variety of factors that affect 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 GHG emission legislation and regulations, fuel costs and availability, weather effects on customer demand, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in the State and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). Volatility in electricity prices may contribute to greater volatility in the Power System's Power Revenue Fund from the sale (and purchase) of electric energy and, therefore, could materially affect the financial condition of the Power System. To mitigate price volatility and the Department's exposure on the spot market, the Department undertakes resource planning activities and plans for its resource needs. Of particular note, the Department has power supply contracts and other arrangements relating to its system supply of power that are of specified durations. See "THE POWER SYSTEM – Generation and Power Supply."

Future Regulation of the Electric Utility Industry. The electric utility industry is highly regulated and is also regularly subject to reform. The most recent reforms and proposals are aimed at reducing emissions of GHGs from combustion of fossil fuels and reducing impacts from using ocean water for power plant cooling. The Department is unable to predict future reforms to the electric utility industry or the impact on the Department of recent reforms and proposals. In particular, the Department is unable to predict the outcome of proposals on reducing GHG emissions and the associated impact on the operations and finances of the Power System or the electric utility industry.

Energy Policy Act of 1992. The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in federal regulation of the electric utility industry, particularly in the area of transmission access under sections 211, 212 and 213 of the Federal Power Act, 16 U.S.C. § 791a et seq. The purpose of these changes, in part, was to bring about increased competition among wholesale suppliers. As amended, sections 211, 212 and 213 authorize FERC to compel a transmission provider to provide transmission service upon application by an electricity supplier. FERC's authority includes the authority to compel the enlargement of transmission capacity as necessary to provide the service. The service must be provided at rates, charges, terms and conditions that are set by FERC. Electric utilities that are owned by municipalities or other public agencies are "transmitting utilities" that may be subject to an order under sections 211, 212 and 213. EPAct 1992 prohibits FERC from requiring "retail wheeling" under which a retail customer that was located in one utility's service area could obtain electricity from another source. An order by FERC to provide transmission might adversely affect the Power System by, and among other things, increasing the Department's cost of owning and operating transmission facilities and/or by reducing the availability of the Department's transmission resources for the Department's own use.

Energy Policy Act of 2005. The Energy Policy Act of 2005 ("EPAct 2005") addresses a wide array of matters that affect the entire electric utility industry, including the Department.

Subject to certain conditions and limitations, EPAct 2005 authorizes FERC to require an unregulated transmitting utility such as the Department to provide electric transmission services at rates that are comparable to those that the unregulated transmitting utility charges itself; and on terms and

conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential FERC may compel open access in this context unless the order would violate a private activity bond rule for purposes of section 141 of the Code (as defined below). To date, FERC has chosen to exercise its authority on a case-by-case approach. Additionally, FERC has the authority to require the provision of transmission services in response to specific requests for service. See ELECTRIC RATES – Rate Regulation. Furthermore, should the Department purchase transmission services from a public utility, as defined in the Federal Power Act, pursuant to the terms and conditions of FERC's *pro forma* OATT, *the pro forma* OATT requires the Department to provide the transmission provider it is purchasing transmission services from, comparable transmission service that it is capable of providing on similar terms and conditions over facilities and for the transmission of electric energy.

EPAct 2005 provides for criminal penalties for manipulative energy trading practices.

EPAct 2005 repealed the Public Utility Holding Company Act of 1935, which prohibited certain mergers and consolidations involving electric utilities. EPAct 2005 gives FERC and state regulators access to books and records within holding companies that include regulated public utilities. In addition, FERC may oversee inter-affiliate transactions within such holding company systems. These provisions of EPAct 2005 are referred to as "PUHCA 2005." PUHCA 2005 does not apply to the Department but generally accommodates more combinations of assets within the electric utility industry.

EPAct 2005 requires the creation of national and regional electric reliability organizations to establish and enforce, under FERC's supervision, mandatory standards for the reliable operation of the bulk power system. The standards are designed to increase system reliability and to minimize blackouts. FERC has designated the North American Electric Reliability Corporation ("NERC") as the national electric reliability organization. FERC has designated the Western Electricity Coordinating Council ("WECC") as the regional reliability organization for utilities in the West, including the Department. Failure to comply with NERC and WECC standards exposes a utility such as the Department to significant fines and penalties. NERC and WECC audit the Department's compliance with the reliability standards once every three years and, as indicated above, impose fines and penalties for non-compliance.

Under EPAct 2005, State IOUs were required to offer, to each of their classes of customers, a time-based rate schedule that would enable customers to manage their energy use through advanced metering and communications technology.

EPAct 2005 authorizes FERC to compel the siting of certain transmission lines if FERC determines that a state has unreasonably withheld approval.

EPAct 2005 promotes increased imports of liquefied natural gas and includes incentives to support the development of renewable energy technologies. EPAct 2005 also extends for 20 years the Price-Anderson Act, which provides certain protection from liability for nuclear power issues and provides incentives for the construction of new nuclear plants.

COVID-19 Pandemic

The COVID-19 pandemic that has affected the United States and the world beginning in the winter of 2020, and which continues as of the date of this Official Statement, has led to efforts to quarantine individuals in order to reduce the spread of the virus. As such, the United States, the State, the County, and the City each declared a "state of emergency" or equivalent. Additionally, the State issued a "stay at home" order, the County issued a "safer-at-home" order, and the City issued a "safer-at-home" order, all of which severely restricted the movements of residents and generally mandated residents to remain in their homes

and, in effect, prohibited non-essential workers from working outside their home. This caused the disruption of daily life in all jurisdictions, including the closure of, among others, bars, dine-in restaurants, retail stores, schools, gyms, movie theatres, certain government buildings and religious institutions, and general prohibitions on gatherings. Initially on June 1, 2020, some of the restrictions on movement were eased, however, beginning in the fall of 2020, as a result of increased infection rates, some of these restrictions were re-imposed. As a result of the progress made through vaccinations and the reduction in the spread of the virus, since January 2021 many of the restriction on movement have again been eased. The Department cannot predict instances of resurgence of the virus (including any of the numerous variants of COVID-19) and if restrictions on movements could once again be re-imposed.

Employees of electric and water utility systems, like the Department, are considered essential workers and are exempt from the "stay at home" and "safer at home" orders issued by the State, the County and the City, and therefore, the Department has continued to fully provide power and water services to its customers since the start of these orders. Due to these orders, the Department implemented several plans to reduce the number of employees in the office to protect their health and well-being. Additionally, in an effort to reduce the risk of transmission of the virus, the Department has, among other measures: (i) implemented telecommuting plans for certain employees; (ii) required the wearing of facemasks for anyone at a job site or on Department property; (iii) enabled field crews to drive to jobsites in separate vehicles; (iv) stressed the critical importance of social distancing in the office and in the field, and (v) reduced meeting sizes while increasing teleconference meetings. These steps have been effective at decreasing the number and congestion of employees in office settings and significantly lessening the risk of transmitting COVID-19 among the workforce. Where instances of employees testing positive for COVID-19 have occurred, the Department has required all of the affected employee's co-workers to immediately self-quarantine consistent with public health guidelines. The Department also is taking steps to ensure the continuation of major infrastructure projects. The Department has developed its "COVID-19 Exposure Control Plan" and a "Facility Specific COVID-19 Viral Transmission Control Plan" for its facilities, in order to facilitate timely implementation of viral transmission controls relating to COVID-19.

The Department has facilitated access to vaccines each week for its employees and has been incorporating and maintaining COVID-19 safety protocols. The Department continues to encourage employees who can work remotely to continue doing so. Approximately 40% of the Department's workforce is working remotely. No date has been set for all employees to return to normal working schedules and locations. The Department is working closely with its labor and management association partners to further develop the specifics of their return to work protocols.

The Department is continually reviewing the effects of the COVID-19 outbreak on the Department, the Power System, and the electric utility industry, generally. In response to the COVID-19 outbreak, the Department has been implementing a number of temporary measures intended to mitigate operational and financial impacts, and to assist the Department's customers, including: (i) to assist customers through any financial hardship that may occur as a result of the COVID-19 outbreak, the Department is widely promoting its existing payment plans and is working on additional extended payment options; (ii) the Department has deferred disconnections of water and power services for non-payment during the COVID-19 pandemic, and currently expects to maintain such deferrals through March 31, 2022; and (iii) the Department restored water and power to a small number of residential customers whose services were disconnected after February 24, 2020, due to nonpayment. As a result of the measures taken by the Department to date, and additional measures that may be taken in the future, the Department has experienced and may continue to experience an increase in delinquent accounts and increase of uncollectible accounts. See "ELECTRIC RATES – Billings and Collections – COVID-19 Response." See "ELECTRIC RATES – Billings and Collections – COVID-19 Response."

The Department cannot predict (i) the duration or extent of the COVID-19 pandemic; (ii) the extent to which the COVID-19 pandemic will affect the operations and revenues of the Power System; (iii) the extent to which the COVID-19 impacts will disrupt the local, State, national or global economy, manufacturing or supply chain, or whether any such disruption may adversely impact Power System-related construction, the cost, sources of funds, schedule or implementation of the Power System's capital improvement program, or other Power System operations; (iv) the extent to which the Department may provide additional deferrals, forbearances, adjustments or other changes to its customers or its billing and collection procedures; or (v) whether any of the foregoing may have a material adverse effect on the finances and operations of the Power System. Prospective investors should consider that the restrictions and limitations instituted related to COVID-19 may increase (even after they are decreased), and upheaval in the national and global economies may re-occur and/or be exacerbated, at least over the near term, and the recovery may be prolonged, and therefore, COVID-19 may adversely impact Power System revenues.

See "ELECTRIC RATES—Billing and Collections."

Changing Laws and Requirements

On both the state and federal levels, legislation is introduced frequently that would have the effect of further regulating environmental impacts relating to energy, including the generation of energy using conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cyber-security legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, and renewable energy incentives that could provide grants and credits to municipal utilities to invest in renewable energy infrastructure. Congress has also considered other bills relating to energy supplies and development. It is possible that the 117th Congress (2021-23) will pass legislation addressing similar issues.

The Department is unable to predict at this time whether any of these or other legislative proposals will be enacted into law and, if so, the impact they may have on the operations and finances of the Power System or on the electric utility industry in general.

In addition to state and federal legislation, citizen initiatives in the State can lead and have led to substantial restrictions upon governmental agencies, both in terms of raising revenue and management of governmental entities generally. Articles XIII C and XIII D of the State's constitution provided limits on the ability of governmental agencies to increase certain fees and charges. Such articles were adopted pursuant to measures qualified for the ballot pursuant to the State's constitutional initiative process. Five lawsuits have been filed generally alleging that the portion of the Power System rates providing moneys to make the Power Transfer constitutes excessive fees and an unauthorized tax for purposes of Article XIII C of the California Constitution. See "LITIGATION – Litigation Regarding Power Transfer."

In addition, from time to time other initiative measures could be adopted by State voters, which may place limitations on the ability of the Department to increase revenues.

Other General Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities, including the Department, and the level of utilization of generation and transmission facilities. In addition to the factors discussed elsewhere herein, such factors include, among others:

- Effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements;

- Changes resulting from conservation and demand-side management programs on the timing and use of energy;

- Effects on the integration and reliability of the power supply from the increased usage of renewables;

- Changes resulting from a national energy policy;

- Effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities and from competitive transmitting of less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity;

- The repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities;

- Increased competition from independent power producers and marketers, brokers and federal power marketing agencies;

- "Self-generation" or "distributed generation" (such as microturbines, fuel cells, and solar installations) by industrial and commercial customers and others;

- Issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission line service from transmission projects financed with outstanding tax-exempt obligations;

- Effects of inflation on the operating and maintenance costs of an electric utility and its facilities;

- Changes from projected future load requirements;

- Increases in costs and uncertain availability of capital;

- Shifts in the availability and relative costs of different fuels (including the cost of natural gas and coal);

- Financial difficulties, including bankruptcy, of fuel suppliers and/or renewable energy suppliers;

- Changes in the electric market structure for neighboring electric grids such as the new EIM operated by the Cal ISO;

- Sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the State;

- Inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity;

- Other legislative changes, voter initiatives, referenda and statewide propositions;
- Effects of changes in the economy, population and demand of customers in the Department's service area;
- Effects of possible manipulation of the electric markets;
- Acts of terrorism or cyberterrorism;
- Natural disasters or other physical calamities, including but not limited to, earthquakes, floods and wildfires, and potential liabilities of electric utilities in connection therewith;
- Adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk; and
- Legislation or court actions allowing City residents and/or businesses to purchase power from sources outside the Department.

Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility, including the Department.

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 March 2015, the Uniform California Earthquake Rupture Forecast (the "2015 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, the Southern California Earthquake Center and the California Earthquake Authority. According to the 2015 Earthquake Forecast, the probability of a magnitude 6.7 or larger earthquake over the next 30 years (from 2014) striking the greater Los Angeles area is 60%. From the Uniform California Earthquake Rupture Forecast published in April 2008 (the "2008 Earthquake Forecast"), the estimated rate of earthquakes around magnitude 6.7 or larger decreased by about 30%. However, the estimate for the likelihood that the State will experience a magnitude 8.0 or larger earthquake in the next 30 years (from 2014) increased from about 4.7% in the 2008 Earthquake Forecast to about 7.0% in the 2015 Earthquake Forecast. The 2015 Earthquake Forecast considered more than 250,000 different fault-based earthquakes, including multifault ruptures, whereas the 2008 Earthquake Forecast considered approximately 10,000 different fault-based 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 OF WATER AND POWER OF THE CITY OF LOS ANGELES – Insurance."

LITIGATION

General

A number of claims and suits are pending against the Department or that directly affect 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.

Litigation Regarding Power Transfer

Three State court lawsuits have been filed generally alleging that the portion of the Power System rates providing moneys to make the Power Transfer (the "Challenged Rates") constitutes excessive fees and an unauthorized tax for purposes of Article XIII C of the California Constitution. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Changing Laws and Requirements." The Department and the City were named as defendants in one State court suit (*Chapman v. The City of Los Angeles et al.*, Los Angeles Superior Court Case No. BS 153395) and the City, but not the Department, was named as a defendant in two State court cases (*Eck v. The City of Los Angeles*, Los Angeles Superior Court Case No. BC 577028 and *Eisan v. The City of Los Angeles*, Los Angeles Superior Court Case No. BC 583788). These three lawsuits were consolidated under the Eck case number (the "Eck Litigation"). The Eck Litigation seeks refunds of the Challenged Rates for various periods and injunctions against the Department charging Power System rates to provide moneys to make the Power Transfer. On April 25, 2016, the court granted the defendants' motion for judgment on the pleadings pursuant to Public Utilities Code Section 10004.5, with leave to amend. On July 1, 2016, the plaintiffs filed an amended consolidated complaint. The parties reached a tentative, class-wide settlement of the Eck Litigation. On or about June 6, 2017, the plaintiffs filed a motion for preliminary approval of the class action settlement. On or about September 14, 2017, a Los Angeles Superior Court judge granted preliminary approval of the settlement. The court granted final approval of the settlement at a hearing on February 14, 2018 and entered judgment on February 26, 2018. The settlement does not have a material adverse effect on the Department's operations or financial position. Certain class members have objected to the settlement and subsequently appealed (2nd Appellate District Case No. B289717). All objections have been dismissed by the Court of Appeal. On December 16, 2019, the Court of Appeal issued a remittitur to the Superior Court indicating that the Court of Appeal's decision is now final, and that the appeal is over.

Under the terms of the settlement, the City, including the Department, has agreed to deduct 8% from the Electric Rates that would be otherwise charged to Power System retail service customers pursuant to the Incremental Electric Rate Ordinance and will no longer transfer any funds the Department derives from the sale of electricity pursuant to the Incremental Electric Rate Ordinance. In addition, the Department established a fund to credit to Power System retail service customers 8% of the total amount billed under the Incremental Electric Rate Ordinance to Power System retail service customers for the period from April 15, 2016 to June 30, 2017, which has been determined to be $33,471,671, which is equal to the final settlement amount after accounting for settlement costs. The credit was applied (in the form of a rate reduction) from April 1, 2020 through March 31, 2021, and from July 1, 2021 through September 30, 2021, and is also expected to be applied from April 1, 2022 through June 30, 2022. The Department's Electric Rates under the Rate Ordinance adopted in 2008—and the City's ability to transfer surplus revenue generated from those rates—remains unchanged.

Legal Actions Related to New Customer Information and Billing System

Lawsuits Brought Against the Department. As discussed in more detail under "ELECTRIC RATES—Billing and Collections" above, numerous issues arose after the Department implemented its customer information and billing system in 2013. Several class action lawsuits were filed against the Department by ratepayers claiming damages due to certain of the billing issues that arose because of these problems with the new system. The Department reached a settlement in certain of those lawsuits (*Sharon Bransford, Steven Shrager and Rachel Tash v. City of Los Angeles et al.*, Los Angeles Superior Court Case No. BC565618; *Haley Fontaine v. City of Los Angeles et al.*, Los Angeles Superior Court Case No. BC571644; *Yaar Kimhi, Tahl Beckerman Megerdichian and Yelena Novak v. The City of Los Angeles, et al.*, Los Angeles Superior Court Case No. BC536272; and *Jones v. City of Los Angeles*, Los Angeles Superior Court Case No. BC577267 (the "Jones Action" and, collectively, the "Settled Billing Class Actions")). On July 20, 2017, the Court granted final approval of the settlement of the Settled Billing Class Actions. The Department is currently implementing the settlement. The settlement provides for, among other things: (1) a review by the Department of all customer accounts for accuracy from September 2013 to December 30, 2016; (2) the Department making whole any customer who was overcharged, regardless of how small the error, resulting from the failed implementation of the customer information and billing system; (3) the Department setting benchmarks and key performance indicators to improve its customer service (an independent monitor reviewed the progress made and reported to the Court every three months through October 2020, at which time his work was completed); and (4) the Department adopting an amendment to its "Rules Governing Water and Electric Service," which generally reduced the number of months that "back-billing" (defined as the submission of a bill by the Department to an accountholder that includes more than one billing cycle where the prior billing statements had not been previously billed to the accountholder) can occur to no more than six months for residential and commercial customers who meet certain characteristics.

Based on billing system queries, the Department previously estimated that the full implementation of the settlement associated with the Settled Billing Class Actions would result in refunds and credits of approximately $67 million. As of November 2021, the Department had issued refunds of $107.9 million, of which $67 million was refunded from the Power System. Reserves for refunds accrued in years prior to Fiscal Year 2017-18 have been reduced given the vast majority of refunds were issued in Fiscal Year 2017-18. The Department has also increased its allowance for doubtful accounts so that as inactive uncollectible accounts are identified, the receivables can be reduced to reflect active, collectible account balances. New methodology for calculating the allowance for doubtful accounts has been implemented in Fiscal Year 2020-21 to ensure an adequate reserve balance for doubtful accounts. Additionally, over the last five years, the Department has invested in additional staff and resources in meter services and field operations, customer billing, customer service and information technology in order to clear backlogs and optimize the billing system.

As of January 30, 2022, the Department had completed the majority of the credits and refunds for accounts associated with the settlement. Accounts remaining to be resolved include those that have been appealed to a court-appointed, independent special master (referenced below) and those that class counsel contends may be entitled to credits or refunds. The Department has ongoing obligations to comply with its "Rules Governing Water and Electric Service," which may result in additional credits being applied. The largest remaining credits and refunds relate to the amendment to the Department's "Rules Governing Water and Electric Service" described above. As part of the settlement described above, the amendment to the Department's "Rules Governing Water and Electric Service" relating to "backbilling" was made retroactive to September 11, 2015. The Department has provided credits and refunds to affected customers relating to the amendment through January 2022 of approximately $39.5 million, of which approximately $24 million was allocated to the Power System.

The Department also implemented operational changes that will allow consistent compliance with the benchmarks and key performance indicators identified in the settlement.

Pursuant to the settlement, KPMG LLP conducted a performance audit of the billing system. KPMG concluded that the billing system was correctly calculating customer bills. KPMG made several recommendations for operational changes, which the Department is implementing. KPMG has completed its second audit of the billing system, as required by the settlement. This second audit again found no errors in bill calculation and proposed several operational changes, which the Department is implementing.

Additionally, another utility expert, Concentric Utility Advisors ("Concentric"), was retained by new class counsel to review the work done on the settlement. In Phase 1 of its review, Concentric reviewed 16 months of billing data and concluded that, with the exception of a small number of manual errors, the terms of the settlement related to incorrect billing had been reasonably met and there were no identified "remaining systemic electric billing issues, and no significant issues (manual or systemic) associated with water, sewer, or refuse" in the accounts reviewed.

Both the KPMG and Concentric reports were filed with the Court. Concentric has completed a limited review of additional work done on the settlement related to the identification of class members in subclasses other than the overbilling subclass (which was already reviewed in its initial report) and is finalizing its report.

Finally, after several mediation sessions, in May 2021, the City and class counsel in the Jones Action entered into a stipulation that resolves all open issues, disputed and undisputed, arising from class counsel's investigation into the settlement. Class counsel has determined that the settlement, including the clarifications in the pending stipulation, is fair, reasonable, and adequate. The Court approved the stipulation at a hearing on September 24, 2021.

In response to concerns raised by counsel for the system implementer for the customer information and billing system regarding potential collusion between former special counsel for the City and former class counsel regarding the filing and settlement of the Jones Action, the Court appointed a special master to conduct an investigation. The results of that investigation were published in July 2021. The special master concluded, among other things, that some City personnel were aware of and participated in the alleged collusion. However, this is not a factual or legal finding of the Court.

The remaining class action lawsuits are (a) *Morski v. City of Los Angeles by, and through, the Los Angeles Department of Water & Power, erroneously sued as the Los Angeles Department of Water & Power*, Case No BC 568722 (the "Morski Action") and (b) *Macias, et al. v. City of Los Angeles by, and through, the Los Angeles Department of Water and Power, erroneously sued as the Los Angeles Department of Water & Power*, Case No. BC594049 (the "Macias Action"). The Morski Action generally alleges that the Department's practice of tiered billing violates applicable City Ordinances insofar as the Department bases such tiered billing on anything other than regular actual monthly meter reads ("Non-Monthly Tiered Billing"). The Macias Action also includes the Non-Monthly Tiered Billing claims, and also alleges "backbilling claims," and that the Department violated California's Bane Act by threatening customers with termination of their utility services based on erroneous charges. The Court has certified three classes, one for each of the above claims in Macias. The parties have filed motions for summary adjudication on each claim, which are set to be heard on May 13, 2022.

Neither case is at a stage where it is possible to estimate the potential financial exposure to the Department.

In July 2019, the City was sued in a class action lawsuit, *Bradshaw v. City of Los Angeles, et al.*, USDC Central District of California Case No. 2:19-cv-07771 (the "Bradshaw Action"), arising out of alleged issues associated with the settlement in the Jones Action. The Bradshaw Action is brought by a ratepayer and member of the Jones Action settlement. After the filing of various defense motions to dismiss and/or stay, on March 23, 2020, the Court stayed the case pending the outcome in the Jones Action based upon the Court's inherent authority. The Court initially deferred ruling on the City's motion to dismiss. However, on September 21, 2021, the Court issued a ruling on the City's previously filed Motion to Dismiss, granting the motion with respect to the Racketeer Influenced and Corrupt Organizations Act ("RICO") claim against the City. The stay remains in place as to all other parties and claims, and as to the remaining Motions to Dismiss. The parties are to submit status reports every 90 days beginning on July 1, 2020. The first report was submitted timely on July 1, 2020**.** Reports have been timely submitted every 90 days thereafter.

On December 21, 2020, Antwon Jones, the class representative in the Jones Action, filed a lawsuit in federal court, Jones v. City of Los Angeles, et al., Case No. 2:20-cv-11502 against the City and other individual defendants claiming violations of 28 USC 1983 (deprivation of civil rights) and Cal. Code of Civil Procedure 526a (taxpayer liability) in connection with, among others, the litigation and settlement of the Settled Billing Class Actions. Jones filed a notice of related case identifying the Bradshaw Action as related. The City and other individual defendants filed motions to dismiss the complaint on March 15, 2021, which were heard on June 21, 2021. The Court granted the motion in part with respect to the taxpayer liability claim, allowing Plaintiff leave to amend. The Court denied the motion with respect to the civil rights claim. In response to Plaintiff's First Amended Complaint the City filed a new motion to dismiss the taxpayer liability claim, as well as a motion to strike the unauthorized amendments to the civil rights claim. The motions were heard on October 4, 2021. The Court granted the City's motion to strike the taxpayer liability claim, but denied the motion to strike as to the amendments to the civil rights claim. The City has filed an answer to the remaining civil rights claim and filed an early motion for summary judgment on February 18, 2022. The Court will hear the City's motion for summary judgment on May 9, 2022.

Federal Investigation. Federal investigators are currently conducting an investigation. The Department is cooperating fully with the investigators in connection with their investigation. The Department has been requested by the investigating agency to exercise confidentiality with respect to the investigation. The Department can generally state that the search warrants served by the Federal Bureau of Investigation on the Department and the Office of the City Attorney, in July 2019, relate to issues that have arisen over the class action litigation and settlement regarding the Department's billing system.

As a result of this investigation, several news articles have been published stating that the impetus for the warrants was the settlement of the class action litigation, among other things. Whether that is the case or not, the class-action settlement agreement included multiple layers of independent review of the Department's decisions on bills, including the right to appeal to a third party and ultimately to the court. In keeping with the City's twin goals of achieving 100% return to ratepayers of all overcharges and fully remediating the billing system, the Department welcomes a thorough review of the settlement, the payout and the programs developed to identify class members. With respect to the current settlement, United States District Court Judge Dickran M. Tevrizian (retired) submitted a declaration expressing his view as the mediator in the class action settlement "…that the settlement is entirely valid; and that the settlement terms are fair, reasonable, adequate, and an excellent outcome for all concerned due to the fact that all ratepayers filing claims will receive 100% of any overcharge."

On November 29, 2021, the U.S. Attorney's Office announced that the former special counsel (the "Former Special Counsel") for the City in a lawsuit against Pricewaterhouse Coopers LLP (who had designed and implemented the Department's customer information and billing system) agreed to plead guilty to a bribery charge for accepting an illegal payment of nearly $2.2 million for getting the former class

counsel to purportedly represent his ratepayer client in a collusive lawsuit against the Department. In his plea agreement, the Former Special Counsel also admitted to additional alleged bribery schemes involving the former General Manager and a former Board member in exchange for the award of a contract benefitting a business venture of such Former Special Counsel. On December 6, 2021, the U.S. Attorney's Office announced that the former General Manager agreed to plead guilty to a bribery charge for accepting bribes from the Former Special Counsel in exchange for his official action to secure a three-year, $30 million no-bid Department contract for the Former Special Counsel's company. On December 13, 2021, the U.S. Attorney's Office announced that the former chief cyber risk officer of the Department agreed to plead guilty to a felony charge of making false statements about a lucrative job offer he secretly solicited and agreed to accept in exchange for providing "guarantees" of additional Department contract money to the Former Special Counsel. On January 10, 2022, the U.S. Attorney's Office announced that the former chief of the civil litigation branch of the City Attorney's Office agreed to plead guilty to a felony charge of aiding and abetting extortion in connection with certain purportedly stolen or improperly retained documents related to the class action litigation regarding the Department's billing system. The federal investigations are ongoing and the Department cannot predict the ultimate outcome.

Based on the Department's understanding of the investigation and the current status of the lawsuits relating to the new billing system, the Department does not believe that the investigation or the billing system related lawsuits will have a material adverse effect on the Department's operations or financial position.

Wildfire Litigation

In recent years, there has been an increase in the number and the severity of wildfires in the State. Due to this increase of fire activity, there has been an increase in litigation filed against power utilities that own and operate generating stations, distribution lines, and transmission lines throughout the State. Currently, the Department is a named party in cases relating to the Creek fire, which ignited on December 5, 2017, and the Getty fire, which ignited on October 28, 2019. The Department denies liability for the ignition of the Creek fire. The unique set of facts regarding the ignition of the Getty fire likely creates Department liability; however, various defense theories and third party claims are being explored.

Creek Fire. Efforts by defense counsel have resulted in the voluntary dismissal in May 2021 of all insurance subrogation litigation cases filed and served against the Department in exchange for a waiver of costs. Videos obtained by defense counsel established the wildfire ignited separate and apart from any Department equipment. The insurance subrogation attorneys were seeking the reimbursement of money paid by insurance carriers to their insureds. The dismissal of those cases represents a reduction of Department exposure in the range of $87 million.

The remaining parties in the Creek wildfire have pending cases in the United States District Court and the Los Angeles Superior Court. The federal case is brought by the United States Forest Service as the plaintiff in *USA v. the Department*. The state court cases are brought by attorneys representing individual plaintiffs all consolidated for litigation in one courtroom. The plaintiff attorneys and insurance subrogation plaintiffs have named Edison as a defendant, focusing on them as the probable ignition source of the Creek fire. Edison has filed but not yet served a cross-complaint for indemnity naming the Department. The federal and state parties are finalizing a discovery agreement to coordinate all discovery, including depositions, to eliminate duplication of discovery efforts.

No new state court cases will be filed because all statutes of limitations have expired. Counsel for the Department continue their effort to obtain dismissals of the Department by the individual plaintiffs attorney group. No trial date is set in the consolidated state court actions. The court and the parties in the state court matter are holding regular status conferences. The Los Angeles Superior Court Judge who has

been handling all state court matters, Judge Daniel Buckley, has announced his retirement, and all state court matters will be reassigned to a new judge, whose identity is not now known, in the next several months. A March 23, 2023 trial date has been set in the federal court case. Also announcing his retirement is the US Attorney who was handling the federal court case.

The United States Forest Service case reflects an approximate exposure of $40 million. The cumulative alleged damages in the State cases is in the range of $150 million, subject to confirmation by damage questionnaires that will be served in the next several months. As noted above, the Department maintains it has no responsibility for the ignition of the Creek wildfire. The Department has approximately $185 million in insurance coverage regarding the Creek wildfire with a $3 million self-insured retention. The excess insurance carrier has been put on notice of the underlying event.

Getty Fire. Regarding the Getty wildfire, there are multiple State court matters all consolidated in one Los Angeles Superior Court courtroom. Additional State court cases may be filed because the statutes of limitations does not terminate until October 2022.

Given the location of the fire, the United States Forest Service is not involved and there is no federal court case in connection with this matter. The court recently lifted the discovery stay and the parties are discussing written and deposition discovery scheduling. The court denied a Demurrer by the Department to the Plaintiffs' First Amended Complaint, specifically a dangerous condition of public property cause of action. The Department is considering the pursue of a Writ with the Appellate Court regarding the Demurrer denial. No trial date has been set.

The Getty wildfire ignited during the early morning hours and involved overhead distribution lines in the Sepulveda Pass area of Los Angeles. The ignition occurred when a tree branch broke off a tree during high wind conditions and subsequently struck the Department distribution lines. The tree from which the branch is believed to have originated is outside of the vegetation clearance area and setback distance required by State regulations. Based upon inspection of the locations, there was no failure of electrical equipment involved. There were no problems or failures of any Department equipment prior to the tree branch striking the overhead lines, and the lines remained intact on the pole. The Department's financial exposure from the Getty fire is not yet known. The 40 insurance carriers who make up the insurance subrogation group have submitted claims totaling $51,726,625, which are now under review. The amount of individual plaintiff group claims is not now known, but will be the subject of a plaintiff questionnaire which must be negotiated and approved by the court. The Department's excess insurance carrier has been put on notice of the underlying event. It has $177.5 million in insurance coverage for the Getty wildfire with a $3 million self-insured retention. Despite not having done anything wrong, the Department could face financial liability claims due to the doctrine of inverse condemnation discussed above under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – Legislation and Court Action Relating to Wildfires."

For details regarding the extent of the Department's current insurance, see "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – Insurance" herein. As discussed under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*" herein, legislation addressing the State's inverse condemnation and "strict liability" issues for utilities in the context of wildfires in particular could have a significant effect on the electric utility industry, including the Department.

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APPENDIX F

CITY OF ANAHEIM

The information contained in this Appendix has been furnished to Intermountain Power Agency (the "Agency") by the City of Anaheim ("Anaheim"). This Appendix presents dated information and neither the Agency nor Anaheim makes any representations regarding the accuracy of the information subsequent to the specified dates. Except as expressly provided, capitalized terms have the meanings set forth in the document to which this Appendix is attached.

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THE CITY OF ANAHEIM ELECTRIC SYSTEM

Organization

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

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

Management of Anaheim Public Utilities

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

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

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

Janet Lonneker, Assistant General Manager–Electric Services, joined Anaheim Public Utilities in May 2014, and is responsible for directing, managing, supervising, and coordinating the activities and

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

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

Public Utilities Board

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

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

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

John Seymour, Chairperson, term expires December 31, 2022. Mr. Seymour joined the Board in April 2017, and was reappointed in March 2019. He is a retired telecommunications executive with a Bachelor's degree from Whittier College in Economics and Business Administration with an emphasis in Accounting. Mr. Seymour previously served on the City's Planning Commission (2010-2017), and is a

former member and chair of the Public Utilities Board's Underground Conversion Subcommittee. He served on the board for the Anaheim Regional Medical Center for over twenty years, and served as a board member for Memorial Health Services.

Vincent Baroldi, Vice Chairperson, term expires December 31, 2022. Mr. Baroldi joined the Board in April 2017, and was reappointed in March 2019. He owns a small business in the City, and has been a resident for over 35 years. Mr. Baroldi holds a Bachelor's degree in Business Administration from University of California, Riverside and a Master's degree in Civil Engineering from California State University, Fullerton. Mr. Baroldi is the treasurer for The Knights of Columbus and sits on the O.C. Diocese Choir Committee and St. Barbara's Finance Committee. He is also a member of the Public Utilities Board's Underground Conversion Subcommittee.

Abdulmageed Abdulrahman, term expires December 31, 2024. Mr. Abdulrahman joined the Board in July 2015, and was reappointed in April 2017. He holds a Bachelor's degree in Mechanical Engineering from Khartoum University, Sudan and a Master's degree in Industrial Management from the University of Central Missouri. He is a licensed Professional Engineer, works as an associate oil and gas engineer with the State of California, and has served on the City's Budget, Investment & Technology Commission (2013-2015), and the City's Ad Hoc Housing Element Committee (2013-2014). Mr. Abdulrahman is also a member of the American Society of Mechanical Engineers and the Society of Petroleum Engineers. He is current serving as the chairperson of the Public Utilities Board's Underground Conversion Subcommittee.

Norma Campos Kurtz, term expires December 31, 2024. Ms. Kurtz joined the board in January 2021. She retired as Associate Vice-President from AT&T where her assignments ranged from service representative to directing corporate contributions. Ms. Kurtz has also held positions at the California Medical Association and the Orange County Labor Federation. She served as District Director for State Senator Joe Dunn (ret.) who represented the Anaheim area, and as District Director for Assembly Member Tom Daly, a former Anaheim mayor. Ms. Kurtz also served as a commissioner on Anaheim's Housing Commission for eight years and is currently a board member for Anaheim Beautiful, a non-profit organization in our city where she chairs the committee responsible for Anaheim's popular home decorating contests – Fall Festival and Holiday Lights.

Ravnish Bhalla, term expires December 31, 2022. Mr. Bhalla joined the Board in March 2019. He is the founder and CEO of Technossus LLC, a privately-held technology consulting firm based in Irvine, California. He holds a Bachelor of Science from Punjab University, and possesses over 25 years of software engineering and development experience. He is a member of the Orange County Technology CEO Forum; a Charter Member of TiE South Coast, a nonprofit fostering entrepreneurship within the community; and a trustee and board member for Shiksha, a charitable organization supporting secondary education for the poor in India. He is also a member of the Public Utilities Board's Underground Conversion Subcommittee.

Mitch Lee, term expires December 31, 2024. Mr. Lee joined the board in August 2021. He retired from the Boeing Company after 20 years as a Deputy Project Manager. Previously, Mr. Lee worked at Northrop for 13 years as an engineer. Throughout his career, he worked on several US and international government and commercial programs. Currently, he is a consultant for MEI Machine Company regarding business/product strategy development and an advisory board member for Theory Seventy Three Corp.

Anh Pham, M.Ed., term expires December 31, 2022. Mr. Pham joined the board in February 2022. He is a policy analyst for the University of California, Irvine and prior to that spent a decade working for the University of California, Riverside. He earned a bachelor of arts degree in public policy as well as a master of education in higher education administration and policy from University of California, Riverside. Mr. Pham's community involvement includes roles with organizations such as ANAHEI'M FIRST, UC Riverside Orange County Alumni Association, West Anaheim Organization and the West Anaheim Neighborhood Development Council.

History of the Electric System

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

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

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

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

Today, the City's power is produced at generating plants in or near the City and at locations across the western United States. The Electric System serves the entire area of the City, covering approximately 50 square miles of the northern portion of Orange County, which is about 28 miles southeast of downtown Los Angeles, and about 90 miles north of San Diego. The City lies on a coastal plain which is bordered by the Pacific Ocean to the west and the Santa Ana Mountains to the east. For the Fiscal Year ended June 30, 2021, the Electric System served an average of 121,526 customers and sold approximately 2,652,150 megawatt-hours ("MWh") of energy to retail customers.

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The table below sets forth historical Electric System resources:

TABLE 1
HISTORICAL RESOURCES
(MW)

	Fiscal Year Ended June 30				
	2021	**2020**	**2019**	**2018**	**2017**
City-Owned Resources					
Kraemer CT Plant[1]	0	0	45	45	45
San Juan, Unit 4[2]	0	0	0	50	50
Non-City Owned Resources					
Hoover	40	40	40	40	40
IPP	236	236	236	236	236
Magnolia	118	118	118	118	118
Canyon Power Project	200	200	200	200	200
Non-City Owned Renewable Resources					
Ormat Technologies	8	8	8	8	8
PPM Energy	32	32	32	32	32
Brea Power Partners	27	27	27	27	27
Cyrq Energy, Inc. subsidiary[3]	7	7	7	7	7
San Gorgonio Farm	31	31	31	31	31
MWD Hydro	10	10	10	10	10
Noble Power and Gas[4]	0	0	0	0	20
Bowerman Power	20	20	20	20	20
Westlands (Westside Solar, LLC)	2	2	2	2	2
Loyalton (ARP Loyalton Cogen, LLC)	1	1	1	1	--
Desert Harvest II	36	--	--	--	--
Total Resources	768	732	777	827	846

(1) The City ceased operation of the Kraemer CT Plant as of December 31, 2019.
(2) The City ceased to have an ownership interest in San Juan, Unit 4 as of December 31, 2017.
(3) Cyrq Energy, Inc.'s former name was Raser Technologies.
(4) The City executed a purchase agreement with Noble Power and Gas for renewable energy from the Stanislaus Resource Recovery Facility for calendar years 2015 through 2016.

Source: Anaheim.

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

Principal Facilities

The Electric System includes generation, transmission and distribution facilities. As of June 30, 2021, the Electric System's principal facilities consisted of approximately 1,200 circuit miles of transmission and distribution lines, and 14 distribution substations. As noted above, the City ceased operation of the Kraemer Combustion Turbine (CT) Power Plant (the "Kraemer CT Plant") as of December 31, 2019.

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

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

TABLE 2
ELECTRIC SYSTEM STATISTICS
($000)

	Fiscal Year Ended June 30,				
	2021	**2020**	**2019**	**2018**	**2017**
Investment in Utility Plants:					
Production	$ 46,103	$ 46,103	$ 46,103	$ 46,103	$ 130,719
Transmission	109,011	101,149	97,371	97,367	97,235
Distribution	1,194,849	1,067,042	1,020,429	1,018,714	1,004,757
General	154,792	151,076	147,295	142,506	137,459
Gross utility plant	1,504,755	1,365,370	1,311,198	1,304,690	1,370,170
Less–accumulated depreciation	(649,346)	(607,682)	(569,045)	(559,890)	(601,412)
Net plant in service	855,409	757,688	742,153	744,800	768,758
Land	34,243	34,243	34,243	34,243	34,243
Construction work in progress	123,368	210,135	208,060	144,398	91,236
Total utility plant	$1,013,020	$1,002,066	$ 984,456	$ 923,441	$ 894,237
Production Costs					
Owned Generation[(1)]	68	$ 805	$ 8,613	$ 19,676	$ 32,537
Purchased Power[(2)]	192,618	201,180	220,342	179,470	200,916
Total Production Costs	$ 192,686	$ 201,985	$ 228,995	$ 199,146	$ 233,453
Transmission-69 kV Circuit Miles	89	88	90	90	90
Distribution Overhead Circuit Miles	391	393	394	399	402
Underground Circuit Miles	764	742	738	714	708
Transformer Capacity (in kVA)					
220 kV to 69 kV	1,808,000	1,808,000	1,808,000	1,808,000	1,808,000
69 kV to 12 kV	1,325,800	1,325,800	1,325,800	1,157,800	1,157,800
12 kV to Customer	1,910,561	1,856,413	1,854,555	1,646,574	1,543,238

(1) Information includes debt service on facilities during the fiscal period.
(2) Excludes transmission costs and gas sold.
Source: Anaheim.

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In the Fiscal Year ended June 30, 2021, the City generated and purchased approximately 2,745,978 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:

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

	Fiscal Year Ended June 30,				
	2021	**2020**	**2019**	**2018**	**2017**
Owned Generation:					
San Juan, Unit 4[1]	0	0	0	182	340
Kraemer CT[2]	0	0	58	49	58
Subtotal	0	0	58	231	398
Firm Purchases:					
Intermountain Power Project	1,063	1,005	1,305	1,112	1,132
Hoover	41	36	37	39	38
Magnolia	418	549	602	622	594
Canyon Power Project[3]	99	93	179	177	145
Renewable Resources[4]	696	693	677	735	826
Subtotal	2,317	2,377	2,800	2,685	2,735
Non-Firm Purchases	429	384	387	303	257
System Total Energy Generated and Purchased, GWh[5]	2,746	2,761	3,245	3,219	3,389
Distribution System Peak Demand, MW	559	530	554	562	535

(1) The City ceased to have an ownership interest in San Juan, Unit 4 as of December 31, 2017.
(2) The City ceased operation of the Kraemer CT Plant as of December 31, 2019.
(3) Canyon Power Project is a peaking unit, and total generation each year varies based on demand and market prices.
(4) Renewable resources vary by year, but meet the RPS requirements, sometimes supplemented with renewable energy credits ("RECs").
(5) Includes energy purchased that was ultimately sold to other utilities. Also includes RECs purchased. Totals may not add due to rounding.
Source: Anaheim.

Power Supply Resources

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

City-Owned Resources

Kraemer Combustion Turbine (CT) Plant. The City owns 100% of the Kraemer CT Plant, a natural gas-fired combustion turbine plant located in the northeast part of the City, adjacent to the City's Dowling Substation. Prior to ceasing operations, the Kraemer CT Plant's available capacity was 45 MW in the winter and 41 MW in the summer. During its useful life, the Kraemer CT Plant was capable of operating for up to 16 hours per day, six days a week for 50 weeks per year, which equates to a maximum of 4,800 annual operating hours. The Kraemer CT Plant began operation in May 1991. Beginning in 2000, operations at the Kraemer CT Plant increased as market conditions changed. The City increased the Kraemer CT Plant's operating hours by participating in the Air Quality Management District's ("AQMD") Reclaim Project and purchased sufficient credits to cover the anticipated NOx emissions associated with its operation as an intermediate unit, rather than just a peaking resource. Over the calendar years 2016 through 2019, the Kraemer CT Plant operated an average of 1,099 hours annually and was primarily utilized to help integrate renewable resources by providing power during peak hours when intermittent renewable resources were not consistently available. In 2018, recognizing the Kraemer CT Plant was nearing the end of its useful life, the City began implementing a gradual ramp down plan for its operation. In the Fiscal Year ended June 30, 2019, the Kraemer CT Plant provided approximately 57.9 GWh of energy to the City. However, since March 2019, the Kraemer CT Plant has not operated because of a turbine that required repair. The City permanently ceased operation of the Kraemer CT Plant as of December 31, 2019 because the repair of the turbine was impractical and cost prohibitive due to the scarcity of repair parts for the turbine's model. Furthermore, there appeared to be only one vendor who could service and repair the turbine and that vendor will cease depot repair of this turbine model on or about December 31, 2022. The City will incur costs to decommission this unit and is setting aside funding for that purpose. The City expects to replace the capacity and energy previously provided by the Kraemer CT Plant with other available resources. See "-Future Power Supply; Cost of Power and Non-Firm Power" below.

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

Regulatory changes and conditions in the last decade impacted the costs and operations of the SJGS. In addition to the implementation of California's cap-and trade program, California legislation was enacted to restrict new investments in baseload fossil fuel electric resources, such as the San Juan Unit 4. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS - State Legislation" in the front part of this Official Statement.

In addition, regulatory proceedings and other related litigation concerning the application of federal Clean Air Act requirements at the San Juan Generating Station were ongoing for a number of years. In settlement of the regulatory proceedings and related litigation, the United States Environmental Protection Agency (the "EPA"), PNM, as the operating agent for the San Juan Generating station, and the New Mexico Environment Department (the "NMED") agreed to pursue a plan that would result in the retirement of the San Juan Generating Station Units 2 and 3 by the end of 2017 and the installation of selective non-catalytic reduction technology on Units 1 and 4 by the later of January 31, 2016 or 15 months after EPA approval of a revised SIP (which installation was completed in January 2016).

In connection with the implementation of the revised plan and the planned retirement of the San Juan Generating Station Units 2 and 3, certain San Juan Generating Station participants, including the City, expressed a desire to exit their ownership in the plant. Definitive agreements for the ownership restructuring of the San Juan Generating Station (the "restructuring agreements") were subsequently executed by all nine San Juan Generating Station owners and PNM Resources Development Company (a non-utility affiliate of PNM) which, following receipt of regulatory approvals, became effective on January 31, 2016. Closing of the ownership restructuring of the San Juan Generation Station and the divestiture of the City's ownership interest was completed on schedule on December 31, 2017. Pursuant to the restructuring agreements, the City (along with the other exiting participants) retains certain liabilities for its respective share of the costs of the SJGS decommissioning and pre-exit date mine reclamation costs. The City's exact proportionate share of such costs cannot yet be determined and will depend on a number of factors, including, among other things, the date the SJGS is ultimately retired from service. Required contributions by the City to the mine reclamation trust funds have been made and a SJGS decommissioning trust fund will be established by future decommissioning cost studies.

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

On June 22, 2004, Edison gave notice of an operating impairment under the SONGS Operating Agreement that would have required the City to contribute approximately $24 million to the cost of a steam generator replacement project. As a result of Edison's action, on October 11, 2004, the City exercised its option not to participate in the work related to the impairment and to reduce its ownership share in accordance with the SONGS Operating Agreement. On December 20, 2005, the City and Edison entered into an agreement for the City to transfer its interest in SONGS to Edison pending Edison's receipt of required regulatory approvals. All approvals were obtained and the transfer became effective on December 29, 2006.

The transfer of the City's interest in SONGS allowed the City to avoid paying the $24 million charge for its share of steam generator replacement cost, to reduce future capital costs associated with its ownership share and to avoid additional future decommissioning costs, which are estimated to range from $24.2 million to $80 million. Such future decommissioning costs would have been in addition to the approximately $129.3 million of such decommissioning costs previously funded by the City.

SONGS Units 2 and 3 have not operated since January 2012. Unit 2 was removed from service on January 9, 2012 for a planned refueling outage and Unit 3 was taken offline on January 31, 2012 after station operators detected a small leak in a tube inside a steam generator manufactured by Mitsubishi Heavy Industries ("MHI"). Originally, Edison intended to return Unit 2 to service at a reduced power level of 70%. However, safety concerns related to the tube leak incident cast doubt as to whether the United States Nuclear Regulatory Commission (the "NRC") would authorize Unit 2's startup and operation at the 70% power output level. After numerous meetings in the public sphere and with the NRC, Edison publically announced on June 7, 2013 its intention to permanently cease power generation operations and shut down Units 2 and 3.

After announcing its intention to shut down Units 2 and 3, Edison began the decommissioning evaluation process, reducing SONGS staff significantly. On September 23, 2014, Edison submitted a decommissioning cost analysis study to the NRC. Based upon Edison's most recent decommissioning cost

study, amounts previously funded by the City and held in trust are expected to fully fund the City's share of SONGS decommissioning costs; however, until the actual total overall decommissioning costs are finally determined, no assurance can be given that additional contributions will not be required by the City. A decommissioning general contractor was selected in December 2016 to decontaminate and dismantle the facility. The decommissioning work is scheduled to be completed by the end of 2028, and full site restoration is expected to be completed by the end of 2049.

Non-City Owned Resources

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

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

Thirty-five utilities (collectively, the "IPP Purchasers") purchase the Intermountain Generating Station's output. The IPP Purchasers include the City, and the California cities of Los Angeles, Riverside, Burbank, Glendale and Pasadena (the "IPP California Participants"); 23 members of IPA, including 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 a construction management and operation agreement between IPA and the Los Angeles Department of Water and Power ("LADWP"), LADWP acts as project manager and operating agent of the IPP, responsible for, among other things, administering, operating and maintaining the IPP. The facilities of the IPP have been in commercial operation since May 1987.

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

In the Fiscal Year ended June 30, 2021, the Intermountain Generating Station operated at a net plant capacity factor of approximately 46.3%. In the Fiscal Year ended June 30, 2020, the Intermountain Generating Station operated at a net plant capacity factor of approximately 43.0%. The Intermountain Generating Station's annual coal requirement is approximately 3.3 million tons. LADWP, in its role as the operating agent of the IPP, buys coal on behalf of IPA under contracts to fulfill this supply requirement of

the IPP. Coal is purchased under a portfolio of fixed price contracts that are of short and long-term in duration. LADWP has reported that IPA has determined that coal presently under contract is sufficient, with the exercise of available options, to meet the IPP's annual coal requirements through 2023. However, LADWP has reported that the cost of coal delivered to the Intermountain Generating Station, as well as the amount of coal delivered, will likely be impacted in 2022 as a result of train delivery disruptions caused by the COVID-19 pandemic, turnover of mining properties in Utah, difficult mining conditions at the remaining mines, increased mining costs due to regulatory oversight, and increases in rail transportation costs. 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 IPP's current plant capacity factors for a minimum of 60 days. With the impact on rail deliveries of coal, IPP participants have agreed to dispatch the project at minimum capacity, which includes running only one of the two generating units, during the first two quarters of 2022 to ensure a sufficient coal supply during the third quarter of 2022. 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 company, and the coal is transported, in part, in IPA-owned railcars. Coal can also be transported, to some extent, in commercial trucks.

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

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

Hoover Uprating Project. The Hoover Uprating Project consists primarily of the uprating of the 17 generating units at Hoover Dam's hydroelectric power plant, located approximately 25 miles from Las Vegas, Nevada. The City's entitlement in the Hoover Uprating Project was approximately 40 MW. A portion of the City's Hoover entitlement became available in June 1987 and the full entitlement became available in June 1993. The Hoover Uprating Project was substantially completed on September 30, 1995. The City originally assigned its entitlement to capacity and energy of the Hoover Uprating Project to

SCPPA (in return for which SCPPA financed the advancement of funds to the United States Bureau of Reclamation for costs of the Hoover Uprating Project) and executed a power sales contract with SCPPA under which the City agreed to make monthly payments on a "take-or-pay" basis for its share of SCPPA's proportionate share of Hoover capacity and allocated energy. These agreements expired on September 30, 2017.

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

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

Canyon Power Project. The City has an entitlement to 100% of the capacity and energy of the Canyon Power Project, which is owned by SCPPA. The Canyon Power Project is located on approximately ten acres of land within an industrial area of the City and is operated and maintained by the City. The Canyon Power Project was constructed for the primary purpose of providing the City with firm capacity and energy to meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The City entered into a power sales agreement with SCPPA pursuant to which the City acquired an entitlement to 100% of the capacity and energy of the Canyon Power Project and is obligated to pay, on a "take-or-pay" basis, 100% of the costs of the project, including all operating and maintenance costs and the costs of debt service on bonds issued by SCPPA in connection with the Canyon Power Project as an operating expense of the Electric System.

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

Participation of Other Parties in Generation Resources

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

capability or output of the defaulting party's share of the project. See also "Indebtedness; Joint Powers Agency Obligations" below.

Renewable Energy Resources

Consistent with State legislation, the City first adopted a Renewables Portfolio Standard ("RPS") on December 16, 2011 that set a target of increasing its purchases of eligible renewable energy resources to 33% within three multi-year compliance periods though 2020. The City met the compliance period target for 2011-2013 (i.e., the procurement of eligible renewable energy resources at least equal to an average of 20% of kWh retail sales over such period), the target for 2014-16 (i.e., the procurement of eligible renewable energy resources totaling at least 20% of 2014 retail sales, 20% of 2015 retail sales, and 25% of 2016 retail sales), the target for 2017-2020 (i.e., the procurement of eligible renewable energy resources equal to at least a total of 27% of 2017 retail sales, 29% of 2018 retail sales, 31% of 2019 retail sales, and 33% of 2020 retail sales), and is currently on track to meet future compliance periods.

For the Fiscal Years ended June 30, 2020 and June 30, 2021, renewable energy resources made up approximately 32% and 35% of the City's total retail energy supply, respectively. Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, signed into law in October 2015, increased the statewide RPS targets to 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. Senate Bill 100, the 100 Percent Clean Energy Act of 2018, signed into law by the Governor on September 10, 2018, further increases statewide RPS targets by requiring retail electric sellers and local publicly-owned electric utilities, such as the City, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027 and 60% of retail sales by December 31, 2030. Senate Bill 100 additionally establishes that it is the policy of the State that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – State Legislation – Renewables Portfolio Standard" in the front part of this Official Statement.

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

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

Ormat Geothermal Contract. The City contracted with Ormat Technologies, through SCPPA, for a 60% share of a 14 MW geothermal project, with the City's share of the project (Heber South-Gould 2), totaling 8.4 MW. The project achieved commercial operation on June 18, 2006, with energy priced at $57.50 per MWh with an annual escalation rate of 1.5% per year. The first amendment to the contract, made on January 25, 2007, allowed the buyer to share production tax credits with the seller in exchange for a $2 per MWh reduction in the price. A second amendment to the contract occurred on May 1, 2008 to increase the project's total capacity from 10 MW to 14 MW with an amendment of the price to $55.50 per MWh in

the first contract year for the first 9.5 MWh delivered each hour and $75.00 per MWh for all energy in excess of the first 9.5 MWh with an annual escalation rate of 1.5% per year applied to both price tiers. Ormat Technologies delivers energy under the contract at the interconnection with the Imperial Irrigation District ("IID") at the Mirage Interconnection tie. The term of the contract expires December 31, 2031, with mutual termination rights at year 2026.

Brea Landfill Contracts. The City executed two power purchase agreements with Brea Power Partners, LP to deliver landfill gas renewable energy. The first short-term contract was for 5 MW with a start date of April 1, 2007 (with power received commencing July 9, 2007) from an existing facility at the Olinda Landfill through (i) the commercial operation date of a second unit or (ii) December 31, 2013. The price for energy from the Olinda Landfill project remained at $69.00 per MWh through December 31, 2008 and then increased to $71.00 per MWh on January 1, 2009, with an annual price escalation thereafter of 2% commencing January 1, 2010. In November 2012, a second long-term contract superseding the original contract was executed, which provides for a total of 27 MW from the new unit at the Olinda Landfill project upon commercial operation of the second unit, which occurred in November 2012. The term of the 27 MW contract is 33 years. The price is $112.50 per MWh with no escalation over the term of the contract.

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

Metropolitan Water District Hydroelectric Contract. The City has contracted with The Metropolitan Water District of Southern California, through SCPPA, for 10 MW of hydroelectricity from a variety of small power plants located at various sites within the Los Angeles Basin. The plants operate as run-of-the-river hydro (in contrast to storage hydro) and as such, energy under the contract is "as available," much like wind. Power deliveries began November 1, 2008, at a price of $94.83 per MWh. An amendment to the agreement occurred in November 2016, reducing the purchase price beginning July 1, 2017 to $54.71 per MWh. The new power price will continue without escalation throughout the remainder of the contract. The contract expires on December 23, 2023.

San Gorgonio Wind Contract. The City executed a power purchase agreement with San Gorgonio Farms, Inc. for 31 MW of wind energy from the existing San Gorgonio Farms Wind Farm located in Whitewater, California. This facility reached commercial operation in 1983 and was originally under contract to Edison. The price for power is split between the environmental attributes and energy. Environmental attributes are priced at $38.50 per MWh with no escalation and the energy price equals the revenue paid by the CAISO for delivery of the project's energy less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. The initial ten-year term of the agreement ends in 2024, with the option to extend for two additional 10-year periods.

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

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

ARP-Loyalton Biomass Project. Through SCPPA, the City has contracted for the purchase of 0.81 MW of energy from the 18 MW Loyalton Biomass Project, owned and operated by American Renewable Power and located in the City of Loyalton, in Sierra County, California. The project reached commercial operation on April 20, 2018. The term of the power purchase agreement is five years. Under the agreement, the City receives its proportionate share of the energy output, capacity, and associated environmental attributes from the project at an estimated cost of $638,000 per year. The agreement assists the City towards its compliance with Senate Bill 859, passed in 2016, which requires local publicly-owned electric utilities in California that serve more than 100,000 customers to procure a proportionate share of a cumulative total of 125 MW of electric generating capacity fueled from high hazard forest materials. In February 2020, the operator of the project, ARP-Loyalton Cogen LLC, and its parent company American Renewable Power LLC, filed petitions for relief under Chapter 11 of the Bankruptcy Code. Both cases were converted to Chapter 7 liquidation proceedings shortly thereafter and a Chapter 7 trustee was appointed. On April 23, 2020, the Chapter 7 trustee entered into an agreement for the sale of the ARP-Loyalton Biomass Project to Sierra Valley Enterprises LLC, a California limited liability company, which sale included substantially all real property and personal property used in the operation of the project. The Bankruptcy Court subsequently approved the sale pursuant to an order entered on May 7, 2020. However, the deadline by which the Chapter 7 trustee must assume or reject the agreement pursuant to the Bankruptcy Code has been continued, and currently expires on May 27, 2022.

Desert Harvest II Solar Project. Through SCPPA, the City has contracted for the purchase of 36 MW of energy from the 70 MW Desert Harvest II Solar Facility, owned by Desert Harvest II, LLC and operated by EDF Renewable Services, Inc. and located near the town of Desert Center in Riverside County, California. The project reached commercial operation on December 17, 2020. The term of the agreement is twenty-five years. Under the agreement the City receives its proportionate share of the facility energy output and associated environmental attributes from the project at an estimated cost of $1,851,000 per year. The agreement assists the City towards its Renewable Portfolio Standard compliance with Senate Bill 100, passed in 2018, which requires that 60% of retail electricity sold in California shall be renewable by 2030.

Distributed Generation; Net Metering

The City's Net Energy Metering ("NEM") Program includes 43.9 MW of participating solar capacity installed to date, which represents 7.4% of the Electric System's peak aggregated load. Under the City's NEM Program, customers are able to receive either the full retail value credit shown in energy on their bill or cash compensation for the excess energy their system generates based on the City's avoided cost of renewable electricity. The City's NEM program includes a legislative goal of 29.6 MW, 5% of the City's peak aggregated load, which was reached in May 2019. Beginning on January 1, 2021, the City

launched its successor NEM Program (known as NEM 2.0),which also compensates customers for providing excess energy from their distributed energy resources, but with compensation adjusted based on the time, day, and season that the energy was supplied to Anaheim's electric grid, reflecting the dynamics of the wholesale energy market's supply and demand.

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

As described above, the City currently has several contracts for firm purchases of power. These contracts accounted for approximately 84% of the City's total energy resources in the Fiscal Year ended June 30, 2021. In addition, the City can replace some of the energy otherwise available from its firm resources with energy purchased from other suppliers throughout the West. These short-term purchases are made under the Western Systems Power Pool Agreement and under bilateral agreements between the City and various suppliers. The City does this when the delivered cost of such energy is less than the variable cost of energy from its long-term resources or when additional energy is needed to meet the City's load. In the Fiscal Year ended June 30, 2021, the City purchased 429 GWh of short-term energy (about 16% of its total energy).

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

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

Fuel Supply

The SCPPA Magnolia Power Project and Canyon Power Project are primarily fueled by natural gas. The City is a participant in SCPPA's Natural Gas Reserves Project and SCPPA's Prepaid Natural Gas Project, which provide the City with approximately 1,500 MMBtu of natural gas daily (or approximately 21% of the City's average daily baseload natural gas consumption).

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

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

Renewable Biomethane. The City has executed a renewable Biomethane Purchase and Sale Agreement with SoCal Biomethane, a subsidiary of Anaergia, Inc., to purchase renewable biomethane derived from food waste, which has been diverted from landfills to a digestions and gas production facility outside of the City. Under the agreement, SoCal Biomethane has the option to produce the renewable biomethane at one of two sites located in either Bloomington or Victorville, California. Once produced, the biomethane would be delivered to the City's power generation facilities through the Southern California Gas Company's pipeline system. Electricity produced using renewable biomethane qualifies as renewable energy under California Energy Commission regulations and helps the City meet its greenhouse gas reduction goals and comply with Senate Bill 350. The renewable Biomethane Purchase and Sale Agreement provides for the purchase of up to 210,240 MMBtu per year at an initial price of $12.74/MMBtu starting in the Fiscal Year ending June 30, 2021, which would escalate annually by an average of 1.4% over the 20-year term of the agreement.

Transmission Resources

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

Mead-Adelanto Project, Authority Interest (Multiple Members). The City is a participant in the SCPPA's member-related interest in the Mead-Adelanto Project. The City entered into a transmission service contract with SCPPA that provides the City with an entitlement share (approximately 118 MW) of the SCPPA's member related ownership interest (the "Authority Interest (Multiple Members)") in the Mead-Adelanto Project and obligates the City to pay for its share of the costs of SCPPA's Authority Interest (Members) in the Mead-Adelanto Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement share is 9.1666% of SCPPA's 67.9167% Authority Interest (Multiple Members) in the project. The City uses the Mead-Adelanto Project for the transmission of energy purchased by the City.

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

Anaheim's CAISO Arrangements

The CAISO began operations on March 31, 1998. The fundamental purpose of the CAISO is to operate the transmission system in a manner that is independent of the interests of the owners of the

transmission facilities to buy or sell energy. The CAISO provides transmission service and related ancillary services to all users, including the City, on a non-discriminatory basis.

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

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Customers and Energy Sales

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

TABLE 4
AVERAGE NUMBER OF CUSTOMERS

	Fiscal Year Ended June 30,				
	2021	**2020**	**2019**	**2018**	**2017**
Residential	103,666	103,366	102,567	101,740	100,480
Commercial	17,466	17,446	17,415	17,386	17,355
Industrial	271	290	297	306	297
Other	112	113	112	120	117
Other Utilities	11	11	12	12	15
Total – All Classes	121,526	121,226	120,403	119,564	118,264

Source: Anaheim.

TABLE 5
TOTAL ENERGY SOLD
(GWh)

	Fiscal Year Ended June 30,				
	2021	**2020**[1]	**2019**	**2018**	**2017**
Residential	630	578	598	593	592
Commercial	660	716	758	798	773
Industrial	739	882	933	922	981
Other[2]	1	1	1	1	1
Other Utilities[3]	622	510	819	846	951
Total – All Classes[4]	2,652	2,687	3,109	3,160	3,298

(1) See "COVID-19 Risks" below.
(2) This category includes streetlights (which comprises 91% of this category) as well as outdoor lights. Previously, non-municipal pumps (which contributed approximately 8.3 GWhs in Fiscal Year 2016-17) were included in the "Other" sales class. Beginning in Fiscal Year 2016-17, non-municipal pumps are grouped in the "Commercial" sales class.
(3) Reflects wholesale sales activity under prevailing market conditions.
(4) The difference between the total GWh generated and purchased shown in Table 3 captioned "Total Gigawatt Hours (GWh) Generated and Purchased and Peak Demand (MW)" and total energy sold as shown in this Table 5 is due to transmission and distribution system losses, wholesale transactions, and RECs.

Source: Anaheim.

During the Fiscal Year ended June 30, 2021, the City satisfied 100% of its power requirements for serving retail customers from its own generation projects and through firm power purchases.

Wholesale Power

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

Major Customers and Economic Conditions

The 10 largest power customers of the Anaheim Electric System, in terms of kilowatt hour ("kWh") sales, accounted for approximately 12% of the Electric System's total energy sales for the Fiscal Year ended June 30, 2021.

Since March 2020, the COVID-19 pandemic has created significant challenges, including a decline in tourism and economic activity in Orange County and within the City. The unemployment rate in Orange County reached 14.9% in Orange County in May 2020, but declined to 4.1% in November 2021. Theme parks, the convention center and sports and entertainment venues in Anaheim were closed for more than a year, drastically impacting hotel stays and visitor spending. On April 30, 2021 the theme parks of the Disneyland Resort reopened to guests. Angels Baseball welcomed back fans to Angel Stadium of Anaheim for the team's home opener on April 1, 2021, with capacity limits lifted on June 15, 2021. See "COVID-19 Risks" below.

While the COVID-19 pandemic presented numerous challenges, Anaheim continues to see economic growth through various expansion and development projects across the City. Throughout the pandemic, City staff ensured plans and permits were reviewed and issued to support business development. Among these are major future developments including those under projects and plans called "OCVibe" and "DisneylandForward."

OCVibe is a planned 95-acre development proposing new homes, shopping, dining, entertainment, hotels, office space, and parks adjacent to the Honda Center. This $3-billion expansion plans to add 1,500 apartments with affordable housing options; four parking structures, surface lots with more than 8,000 spaces; 10 acres of publicly accessible parks; four public plazas, including an outdoor amphitheater; a new 5,700-seat concert venue; more than 30 restaurants including a 68,000 square-foot food hall; two new hotels collectively adding over 500 rooms; more than one million square feet of office space; and over 8,000

parking spaces in structures and surface lots. The project application was submitted to the City in fall 2020 with construction expected to start in 2023.

Disney and the City have launched DisneylandForward, a multiyear public planning effort to expand and update Disneyland theme parks, hotel offerings, entertainment, parking, restaurants, and more. This plan allows Disney to further invest in Anaheim for years to come.

Electric Rates and Charges

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

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

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

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

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

The RSA collections are treated as deferred inflows for accounting purposes and are used by management to mitigate material fluctuations in the cost of energy, loss of revenues or unbudgeted costs including the unexpected long-term loss of a generating facility, unplanned limits on the ability to transmit energy to the City, or disasters that could otherwise negatively affect the revenue stream. At management's discretion, amounts in the RSA accounts may be withdrawn and recognized as gross revenues of the Electric System in order to maintain sufficient debt service coverage ratios. See Table 10 for information regarding such withdrawals in recent years. As of June 30, 2021, the balance in the RSA regulatory credit account was approximately $103.0 million, prior to any RSA recognized for the fiscal year ended June 30, 2021.

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

Currently, the PCA charge is 1.0¢ per kWh for usage by residential customers above prescribed base (first tier) levels, 1.0¢ per kWh for usage by general commercial, industrial and municipal customers, and 0.48¢ per kWh for large commercial customers. The EMA charge is currently 1.05¢ per kWh for usage by residential, general commercial, industrial, and municipal customers, and 1.28¢ per kWh for large commercial customers. In addition, all classes pay an undergrounding surcharge equal to 4% of base rate charges (exclusive of RSA) in order to fund the conversion of overhead power lines into underground lines throughout the City. The City does not impose a utilities' user tax.

The base electric rates were last revised by the City Council on September 1, 2015. This action restructured rates by increasing base rates with corresponding decreases to the PCA and EMA. There was no increase or decrease in overall electric rates as a result. More recently, administrative updates were made to select rate schedules to improve consistency in the application of demand charges across rate schedules. Additionally, time of use periods were revised for the Feed-In-Tariff rate and base rates were modified for the Thermal Energy Storage rate to accommodate the administrative changes noted above (without having the effect of increasing or decreasing the net rate revenue). Recently established optional rates include electric vehicle rate schedules for residential and business customers, and a new time-of-use rate schedule for residential customers. In addition, formulas used to calculate compensation paid to net generators under the Feed-In-Tariff and Net Energy Metering rate schedules were updated. Modifications to the Developmental Net Energy Metering rate schedule were recently adopted that include adding a successor Net Energy Metering option and closing the current net energy metering option to new customers, effective January 1, 2021. The Thermal Energy Storage rate schedule was also revised to align time-of-use periods with regional demand for energy and adjust rates to improve cost recovery. The City's current primary rate schedules for residential, commercial and industrial customers of the Electric System are set forth in Table 6 below.

TABLE 6
PRIMARY RATE SCHEDULES FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS
(As of June 30, 2021)

Type and Description of Service	
Domestic Services Single Family Customers (Basic):	
Customer Charge, per meter, per month	$ 5.00
Energy Charge (added to Customer Charge):	
First 10 kWh per day, cents per kWh	12.00
All Excess kWh, cents per kWh	19.74
General Service Small Commercial Customers:	
Customer Charge, per meter, per month	$ 15.00
Energy Charge (to be added to Customer Charge):	
All kWh, cents per kWh	17.62
General Service Medium Commercial Customers:	
Customer Charge	$ 46.97
Demand Charge (added to Customer Charge)	
First 15 kW or less of billing demand	126.20
All excess kW of billing demand per kW	12.27
Energy Charge (added to Demand Charge)	
All kWh, cents per kWh	12.14
General Service Large Commercial and Industrial Customers:	
Customer Charge, per meter, per month	$ 360.91
Demand Charge (to be added to Customer Charge):	
First 200 kW or less of billing demand	2,769.00
All excess kW of billing demand, per kW	15.65
Energy Charge (to be added to Demand Charge):	
For the first 540 kWh per kW of billing demand, cents per kWh	11.35
All excess kWh, cents per kWh	8.13

	Summer	Winter
General Service Optional Time of Use Rate:		
Customer Charge, per meter, per month:	$342.12	$342.12
Demand Charge (added to Customer Charge):		
Non-Time related Maximum Demand, per kW	8.66	8.66
Plus all on-peak billing demand, per kW	15.68	N/A
Plus all mid-peak billing demand, per kW	5.47	5.74
Plus all off-peak billing demand, per kW	N/A	N/A
Energy Charge (added to Demand Charge):		
All on-peak energy, cents per kWh	14.80	N/A
Plus all mid-peak energy, cents per kWh	11.71	12.48
Plus all off-peak energy, cents per kWh	7.87	7.87

Source: Anaheim.

Litigation Challenging Electric Rates. On October 3, 2017 and November 2, 2018, the City was served with two class action lawsuits generally alleging the City's electric rates constitute an unauthorized tax for purposes of Article XIIIC of the California Constitution ("Article XIIIC") because the rates are designed to fund the 4% general fund transfer and 1.5% right of way fee for general governmental services which are unrelated to the provision of electric services. The complaints are seeking a refund, on behalf of the plaintiff (an Electric System customer) ("Plaintiff") and a class of others similarly situated, of paid electric rates and other relief. The court instructed Plaintiff to file a revised complaint in the 2017 action that combines the allegations and claims of both the 2017 and 2018 lawsuits without prejudice to either

party's existing rights. On October 28, 2019, the court issued an order requiring Plaintiff to file and serve a Second Amended and First Supplemental Complaint, and on November 19, 2019, Plaintiff served the City with the same to which the City filed a response on December 17, 2019. On June 8, 2020, the court certified the class. This litigation is ongoing. See "– Litigation Affecting the Electric System – *Lawsuit Challenging Electric Rates*" below.

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

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

	Fiscal Year Ended June 30,				
	2021	**2020**	**2019**	**2018**	**2017**
Residential	18.13	17.46	16.99	16.69	16.90
Commercial	19.38	18.69	18.15	17.54	17.79
Industrial	16.49	15.89	15.22	14.66	14.75
Other	16.63	15.84	15.43	14.62	14.61
System Averages	17.94	17.23	16.65	16.20	16.29

Source: Anaheim.

Cost Recovery and Reserves. APU's electric rates include components that largely decouple revenues from sales and allow for the timely recovery of costs and achievement of financial goals. APU management has the ability to raise up to approximately $65 million per year using its rate mechanisms, if necessary, without a vote or approval by the City Council. These rate mechanisms, coupled with financial reserves equal to approximately 200 days of operating expenses and a $100 million revolving line of credit with Wells Fargo Bank, N.A., provides APU with the means to offset potential lost revenue from reduced retail sales and/or increased costs.

Capital Improvements Plan

As part of its planning process, the City identified the following Electric System capital improvement projects through the Fiscal Year ending June 30, 2026 (the "Five-Year Plan"), totaling approximately $447.4 million:

	Five-Year Plan 2021-22 through 2025-26 ($000)
System Undergrounding	$99,125
Battery Storage	75,000
Transmission & Distribution	58,900
Transformer Replacement	58,750
Electric Facilities & Street Lights	53,050
Substation Improvements	45,046
Direct Buried Cable & System Expansion	33,600
System Protection, Automation and Telecommunications	23,925
Total	$447,396

The electric capital programs aim to improve electric service reliability, enhance system resiliency, improve operational efficiencies, support system growth, and integrate renewable resources. System undergrounding projects place overhead electrical and communication infrastructure along Anaheim's major thoroughfares underground, including high fire threat zone areas for wildfire mitigation. Transmission and distribution expansion projects replace aging overhead electrical and communication facilities with new underground facilities to improve overall system reliability, public safety, and aesthetics. The transformer replacement program repairs and replaces existing overhead transformers to reduce the likelihood of emergency repairs. Electric facilities and street lights include the deployment of advanced metering infrastructure; construction of a backup operations and crew quarters facility; and street light upgrades. Projects involving the Electric System's distribution substations include enhancements to existing substations that will improve reliability and provide sufficient flexibility and capacity for future electric load growth. Battery storage projects support the integration of intermittent renewable resources by storing power when there is an abundance of energy available and distributing when energy prices are high. Direct buried cable projects replace aged and deteriorated cable with more resilient conduit. System expansion projects support the growth of electric transmission and distribution facilities to serve new or expanding residential, commercial, or industrial properties. System Protection and Automation includes the electric system automation, protection, and Supervisory Control and Data Acquisition ("SCADA") upgrades to enhance the resiliency and flexibility of the electric distribution system while telecommunication projects upgrade and expand the fiber optic infrastructure to enable automation.

The City funds its capital plan through a combination of long-term financing, pay-as-you-go, and other resources. The City is in the bond market on a periodic basis to fund appropriate capital projects based on its planning models. The City currently anticipates it will finance approximately 41% of the capital costs identified in the Five-Year Plan through existing and new bond proceeds. These projections may change based on deferrals of Electric System capital improvement projects or changes in the mix of financial resources used to fund capital projects. See "COVID-19 Risks" below.

Insurance

The Electric System participates in the City's self-insured workers' compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to the City in consideration of self-insurance premiums paid by the Electric System. Premiums for workers' compensation and general liability programs are charged to the Electric System by the City based on various allocation methods that include actual cost, trends in claims experience, exposure base, and number of participants. Premiums charged and paid totaled $2,824,000 and $3,206,000 for the years ended June 30, 2020 and June 30, 2021, respectively.

At June 30, 2021, the City was fully funded for self-insured workers' compensation and general liability claims (self-insured retention levels of $2,000,000 per occurrence for workers' compensation claims and $1,000,000 per occurrence for general liability claims). Above these self-insured retention levels, the City's potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded total insurance coverage in any of the past three years, nor does management believe that there are any pending claims that will exceed total insurance coverage.

Wildfire Mitigation Measures

A portion of the Anaheim Electric System service area encompasses geographical areas classified by the CPUC's Fire Threat Map as a "Tier 2" or "Tier 3" fire-threat area (i.e., an area of elevated or extreme risk from utility-associated wildfires). Within the four Tier 3 fire-threat zones within the City's boundaries (representing 13.86% of the City), approximately 98% of City-owned power lines are currently

underground, and the remaining above-ground power lines in Tier 3 fire-threat zones are de-energized unless needed to be utilized for the distribution of electricity to the City. These factors significantly reduce the risk of electric infrastructure being a contributing factor to the ignition of a wildfire in extreme fire-risk areas. Approximately 0.61% of the geographical area served by the Anaheim Electric System is identified as a Tier 2 fire threat zone. The City currently has in place a number of wildfire prevention strategies and emergency response measures. APU conducts routine inspections of distribution equipment, which includes the overhead system (poles and associated overhead conductors and equipment), as well as underground substructures and above surface equipment. APU performs ongoing vegetation clearance and management activities, with increased clearances established for overhead power lines in high risk fire areas. The City also has instituted emergency preparedness and response measures and protocols, including annual workforce emergency response training, the flexibility to de-energize overhead lines and re-route power during outages and emergencies with limited disruption in service, and the ability to eliminate the automatic reclosing capability of protective relays on certain transmission lines located with a Tier 3 fire-threat zone during dangerous weather conditions to require that power to a tripped line is only restored after manual inspection and confirmation that it may be operated safely. Pursuant to the California legislative requirements, the City Council approved an updated wildfire mitigation plan and an independent evaluator's report was presented in May 2020. The plan was submitted to the California State Wildfire Advisory Board prior to the July 1, 2020 deadline. See also "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – State Legislation – *Legislation Relating to Wildfires; Related Risks*" in the front part of this Official Statement.

Transfers to the General Fund

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

For information regarding the amount of the Charter-authorized transfers of Electric System funds to the City's General Fund during each of the last five fiscal years, see "– Historical Financial Results" below. See also "– Electric Rates and Charges – Litigation Challenging Electric Rates" for a discussion of ongoing litigation relating to the Charter-authorized transfers.

Indebtedness; Joint Powers Agency Obligations

Direct Obligations. As of April 4, 2021, in addition to its obligations under its joint powers agency contracts (see "– Joint Powers Agency Obligations" below), the City had outstanding $612,360,000 principal amount of long-term obligations payable from Electric System revenues, consisting of installment purchase payments ("Qualified Obligations") payable by the City under installment purchase agreements with the Anaheim Housing and Public Improvements Authority ("AHPIA"), the Anaheim Public Financing Authority ("APFA"), or the California Municipal Finance Authority ("CMFA") relating to bonds issued by AHPIA, APFA, or CMFA for the benefit of the Electric System, which are payable from surplus Electric System revenues after payment of maintenance and operations expenses of the Electric System and the replenishment of certain reserves and other funds.

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The outstanding Qualified Obligations are summarized in the table below.

TABLE 8
OUTSTANDING QUALIFIED OBLIGATIONS
(as of April 4, 2021)

Issue	Date of Installment Purchase Agreement	Principal Amount Outstanding
Anaheim Public Financing Authority Revenue Refunding Bonds, Series 2012-A (Electric Distribution System Refunding)[1]	09/01/12	$ 61,535,000
California Municipal Finance Authority Revenue Refunding Bonds, Series 2014-A (City of Anaheim Electric Utility Distribution System Refunding)	10/01/14	43,355,000
California Municipal Finance Authority Revenue Refunding Bonds, Series 2015-B (City of Anaheim Electric Utility Distribution System Refunding and Improvements)[1]	06/01/15	61,835,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2017-A (Electric Utility Distribution System Refunding)	12/01/17	38,855,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2017-B (Electric Utility Distribution System Refunding)[1]	12/01/17	190,415,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2020-A (Electric Utility Distribution System Improvements)[1]	03/01/20	58,345,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-B (Electric Utility Distribution System Refunding)	03/01/20	115,680,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-C (Electric Utility Distribution System Refunding)[1]	03/01/20	42,340,000

[1] Bonds proposed to be refinanced with the 2022 Bonds. See "PLAN OF FINANCE" in the Official Statement.
Source: Anaheim.

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

Any outstanding Electric System borrowings of the City under the Revolving Credit Agreement which have not been paid (which borrowings may be paid from, among other sources, proceeds of future long-term financings of the City) on or prior to the facility maturity date of the Revolving Credit Agreement (i.e., currently December 31, 2023, unless extended) will be automatically converted to term loans on such date, so long as no default or event of default by the City shall have occurred and be continuing and all representations and warranties of the City under the Revolving Credit Agreement are true and correct in all material respects as of such date. Any term loans made by the Credit Bank under the Revolving Credit

Agreement will bear interest at a variable per annum rate of interest equal to: for taxable borrowings, a spread of 0.85 percent (so long as the current credit ratings on the City's Qualified Obligations is maintained) to a LIBOR rate; and for tax-exempt borrowings, at a spread of 0.70 percent (so long as the current credit ratings on the City's Qualified Obligations is maintained) to, at the option of the City, either (i) a factor of a LIBOR term rate or (ii) a LIBOR daily index rate. Principal on any such term loans would be payable by the City in quarterly installments over three years. The occurrence of an event of default by the City under the Revolving Credit Agreement (including, among other things, a failure by the City to pay principal or interest thereunder, a failure by the City to perform or observe its covenants, a default in other specified indebtedness of the City, certain acts of insolvency, or a reduction by any of S&P, Fitch, or Moody's in the credit ratings assigned to any debt secured by surplus Electric System revenues or the City's Water System revenues to below "A–" by S&P and Fitch or "A3" by Moody's), may result in an increase in the interest rate payable by the City on any outstanding Electric Revenue Anticipation Notes or term loans under the Revolving Credit Agreement and/or an acceleration (depending on the event, seven days after the occurrence, or for certain events, only after 180 days' notice) in the payment of the principal of any such outstanding Electric Revenue Anticipation Notes or term loans in accordance with the terms of the Revolving Credit Agreement. The City intends to replace the current Revolving Credit Agreement upon maturity.

The Revolving Credit Agreement is also available for Water System borrowings. Borrowings for the Water System will reduce the commitment available under the Revolving Credit Agreement by an amount corresponding to such Water System borrowing.

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

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TABLE 9
OUTSTANDING DEBT OF JOINT POWERS AGENCIES AND ANAHEIM'S SHARE
(as of June 30, 2021)

	Principal Amount of Outstanding Debt	Anaheim's Participation[1]	Anaheim's Share of Principal Amount of Outstanding Debt[2]
Intermountain Power Agency			
Intermountain Power Project[2]	$ 239,974,166	13.225%	$ 31,736,583
Southern California Public Power Authority			
Southern Transmission System	$ 317,415,000	17.647%	$ 56,014,225
Magnolia Power Project[3]	241,440,000	39.683	95,811,118
Prepaid Natural Gas Project[4]	277,105,000	16.500	45,722,325
Natural Gas Reserves	25,615,000	100.000	25,615,000
Canyon Power Project	271,315,000	100.000	271,315,000
Subtotal	$1,132,890,000		$494,477,668
Total	$1,372,864,166		$526,214,252

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds and the Canyon Power Project bonds).
(2) Includes bonds, commercial paper and subordinate notes.
(3) Excludes bonds relating solely to City of Cerritos.
(4) Not a "take-or-pay" obligation; the City must pay for contracted natural gas only to the extent delivered.
Source: Anaheim.

For the Fiscal Year ended June 30, 2021, the City estimates that debt service payments on its joint powers agency obligations totaled approximately $77.6 million. Annual debt service on the City's joint powers agency obligations is expected to decrease from this level to approximately $19.1 million in the Fiscal Year ending June 30, 2040. 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 2.25%. Currently, all joint powers agency debt that Anaheim is a participant in is either fixed or fully-hedged if variable. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above and may be subject to repayment to the liquidity provider over a significantly shorter period than the originally scheduled payment of principal on the related bonds. Interest rate swap agreements entered into by joint powers agencies in connection with hedged variable rate joint powers agency obligations may be subject to early termination. In the event of early termination of a joint powers agency interest rate swap agreement, the joint powers agency could be obligated to make a substantial payment to the applicable swap provider, a corresponding amount of which termination payment (proportionate to each project participants' participation share in the related project) could be due from the applicable project participants.

Accounting Policies

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

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

For further information concerning the Electric System's financial position, see the audited financial statements of the Anaheim Electric Utility Fund for the Fiscal Year ended June 30, 2021 in APPENDIX B – "AUDITED FINANCIAL STATEMENTS OF THE ANAHEIM ELECTRIC UTILITY FUND FOR THE FISCAL YEAR ENDED JUNE 30, 2021."

KPMG LLP, certified public accountants, audited the City's Electric Utility Fund financial statements for the Fiscal Year ended June 30, 2021, included in Appendix B to this Official Statement. The City did not request the consent of KPMG LLP to include its report in Appendix B, and KPMG LLP has not undertaken to update its report or to take any action intended or likely to elicit information concerning the accuracy, completeness or fairness of the statements made in this Official Statement, and no opinion is expressed by KPMG LLP with respect to any event subsequent to the date of its report.

Historical Financial Results

The following table shows a summary of the financial results of the Electric System for the five full Fiscal Years shown. The following table also sets forth the calculation of debt service coverage of outstanding Electric System obligations for the full Fiscal Years ended June 30, 2017 through June 30, 2021. The information for the Fiscal Years ended June 30, 2017 through June 30, 2021 is based on the audited financial statements of the City's Electric Utility Fund for such periods.

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

	Fiscal Year Ended June 30,				
	2021	**2020**	**2019**	**2018**	**2017**
Revenues					
Sale of electricity:					
Residential	$ 99,110	$ 95,299	$ 99,321	$ 97,586	$ 97,204
Commercial	116,632	125,383	131,998	138,140	134,231
Industrial	112,698	130,767	131,553	135,631	142,699
Other	3,568	3,867	4,092	5,772	4,489
Other Utilities (wholesale)	27,286	14,498	38,138	28,879	24,372
Billed revenue from sale of electricity[1]	$359,294	$369,813	$405,103	$406,008	$402,995
Change in unbilled electric revenue[1]	-	-	-	694	(1,852)
Total revenue from sale of electricity	$359,294	$369,813	$405,103	$406,702	$401,143
RSA revenue	35,000	17,250	15,000	0	0
Other (including general interest income)[2]	40,937	39,673	48,973	40,148	34,693
Total gross revenues	$435,231	$426,736	$469,076	$446,850	$435,837
Expenses (excluding depreciation and amortization)					
Cost of purchased power[3]	$250,867	$265,626	$295,540	$244,687	$263,729
Fuel and generation[4]	68	805	8,613	19,676	19,337
Operations & Maintenance	57,909	67,526	56,260	60,429	50,128
Right of Way fee	5,530	5,668	5,570	5,584	5,694
Total expenses	$314,374	$339,625	$365,983	$330,376	$338,888
Net revenues	$120,857	$ 87,111	$ 103,093	$116,474	$ 96,949
Deposits to Renewal and Replacement Account	1,954	(397)	(244)	(374)	(122)
Surplus Revenues(a)	118,903	$ 87,508	$ 103,337	$116,848	$ 97,071
Qualified Obligations purchase payments(b)[5]	58,765	50,335	50,410	51,086	47,898
Second Lien Qualified Obligations(c)[6]	-	815	951	832	571
Net revenues after debt service payments	60,138	$ 36,358	$ 51,975	$ 64,930	$ 48,602
Transfers (to) Anaheim General Fund	(16,667)	(18,322)	(17,444)	(17,028)	(19,032)
Transfers (to)/from other Anaheim funds	179	277	227	492	53
Balance for other purposes	$ 43,650	$18,313	$ 34,758	$ 48,394	$ 29,623
Qualified Obligation (incl. Second Lien) debt service coverage (a/(b+c))	2.0x	1.7x	2.0x	2.3x	2.0x

(1) Beginning with Fiscal Year 2018-19, change in unbilled revenue no longer reported separately and reflected instead in billed revenue from sale of electricity.

(2) The other revenues include transmission revenues, natural gas sales and interest income. Other revenue was restated to exclude capital grants from operation revenue based on GASB 34.

(3) Includes take-or-pay obligations with joint powers agencies. Cost of Purchased Power includes transmission costs and natural gas costs. Cost of Purchased Power reflects use of carbon allowance credits from the CARB to reduce renewable energy expenses.

(4) Fuel and generation includes all expenses associated with the operation of the Kraemer CT Plant and the SJGS Unit 4, which are no longer in operation.

(5) Qualified Obligations outstanding at June 30, 2021 include $42,340,000 AHPIA Revenue Refunding Bonds, Series 2020-C (Electric Utility Distribution System Refunding); $118,955,000 AHPIA Revenue Refunding Bonds, Series 2020-B (Electric Utility Distribution System Refunding – Taxable); $59,215,000 AHPIA Revenue Bonds, Series 2020-A (Electric Utility Distribution System Improvements); $194,330,000 AHPIA Revenue Refunding Bonds, Series 2017-B (Electric Utility Distribution System Refunding); $42,955,000 AHPIA Revenue Refunding Bonds, Series 2017-A (Electric Utility Distribution System Refunding); $835,000 AHPIA Revenue Bonds, Series 2016-A (Electric Utility Distribution System Refunding and Improvements); $67,735,000 CMFA Revenue Refunding Bonds, Series 2015-B (City of Anaheim Electric Utility Distribution System Refunding and Improvements); $56,070,000 CMFA Revenue Refunding Bonds, Series 2014-A (City of Anaheim Electric Utility Distribution System Refunding) and $62,990,000 APFA Revenue Refunding Bonds, Series 2012-A (Electric Distribution System Refunding).

(6) Second Lien Qualified Obligations outstanding at June 30, 2019 include $50,000,000 CMFA Revenue Bonds, Series 2015-A which were refunded in full on March 4, 2020.

Source: Anaheim.

Management's Discussion of Fiscal Year 2020-21 Operating Results

Gross revenues for the Fiscal Year ended June 30, 2021 were approximately $435.2 million, an increase of $8.4 million or 2.0% from the prior fiscal year, mainly due to an increase of $12.8 million in wholesale sales as well as the recognition of RSA revenues in the amount of $35.0 million. The increase was partially offset by a net decrease in retail sales of electricity of $23.0 million, primarily due to the shelter-at-home restrictions from the pandemic, with hotels, theme parks, and other entertainment venues remaining closed most of the Fiscal Year ended June 30, 2021.

Total retail sales decreased by $23.0 million or 6.5% for the Fiscal Year ended June 30, 2021 compared to the prior fiscal year. Residential sales declined by approximately $3.8 million or 4.0%, primarily as a result of lower than average temperatures and continued customer adoption of solar and energy efficiency measures. Commercial and industrial sales decreased by approximately $26.8 million or 10.5% compared to the previous fiscal year primarily as a result of public health orders. Continued adoption of solar and energy efficiency measures by commercial and industrial customers also contributed to lower retail sales. Anaheim Public Utilities recognized approximately $35.0 million in RSA revenues to partially offset the lower sales revenues. The RSA component of APU's rate structure provides flexibility to recover costs and manage fluctuations in revenues. See also "– Electric Rates and Charges" for a discussion of the City's electric rate structure.

Wholesale sales increased by approximately $12.8 million or 88.2% for the Fiscal Year ended June 30, 2021 compared to the prior fiscal year. The public health restrictions allowed excess electricity to be sold in the wholesale markets. High wholesale market energy prices caused more generation units to be dispatched to accommodate demand which in turn generated more revenues related to wholesale sales.

Other revenues, comprised of surplus natural gas sales, transmission revenue, and interest income, increased by approximately $1.3 million or 3.2% for the Fiscal Year ended June 30, 2021. Transmission revenue and surplus natural gas sales increased by $5.5 million and $3.0 million, respectively, which were offset by a decrease of $7.3 million in investment income.

Total operating expenses for the Fiscal Year ended June 30, 2021 were approximately $314.3 million, a decrease of $25.3 million or 7.4% from the prior fiscal year primarily due to lower purchased power expenses. Cost of purchased power was approximately $250.9 million for the Fiscal Year ended June 30, 2021, a decrease of approximately $14.8 million or 5.6% due to lower demand for electricity in the retail sector due to public health restrictions.

Labor Relations

As of June 30, 2021, APU has a total of 352 full-time and 52 part-time authorized positions. Of this total, the International Brotherhood of Electrical Workers ("IBEW") Local 47 represents, cumulatively, 210 full-time and 38 part-time employees, the American Federation of State, County, and Municipal Employees District Council 36 ("AFSCME") represents approximately 133 full-time positions and 12 part-time employees; and the Anaheim Municipal Employees Association ("AMEA") represents 9 full-time employees and 2 part-time employees. Effective January 24, 2020, the City of Anaheim and IBEW, Local 47 established a three year memorandum of understanding for professional management and part-time management units. The professional management classifications include all of APU's Civil Engineers, Electric System Designers, SCADA Analysts, and Assistant and Associate Power Engineers. The IBEW memorandum of understanding, commonly referred to as IBEW-Craft, expires December 2022. The memorandum of understanding with AMEA extends through June 23, 2022. The City negotiated with AFSCME regarding a new memorandum of understanding and reached an agreement establishing a new memorandum of understanding, effective December 24, 2021. The City has not experienced any strike, work stoppage or other labor action by APU's employees in the last five years.

Retirement Programs

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

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

The cost of the Miscellaneous Plan is funded through bi-weekly contributions from employees and from employer contributions by the City. Miscellaneous Plan employees hired prior to January 1, 2013 are generally required to contribute 8.00% of their annual covered salary. Miscellaneous Plan members hired on or after January 1, 2013 and who have no prior membership in any California public employee retirement system are required to contribute 6.75% of their annual covered salary. The member contribution can be paid by the employee or by the City on the employee's behalf in accordance with applicable labor agreements. The majority of Miscellaneous Plan employees hired prior to January 1, 2013 contribute the full 8.00% employee contribution plus 4.00% of the employer contribution, for a total of 12.00%. For employees hired on and after January 1, 2013 that are required to contribute at an employee rate of 6.75% of annual covered salary, the entire 6.75% is paid by such employees. In accordance with applicable State law, the contribution rate for all public employers is determined annually by the actuary and is effective on the July 1 following notice of a change in rate. Funding contribution amounts are determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate applied to annual payroll is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the actuarially determined remaining amounts necessary to fund the benefits for its members, using the actuarial basis recommended by CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. CalPERS establishes and amends the employer contribution rates. Beginning with Fiscal Year 2017-18, CalPERS began collecting employer contributions toward the plan's unfunded liability as dollar amounts rather than percentage of active payroll. For the Fiscal Year ended June 30, 2021, the City's required employer contribution rate for the normal cost component of required contributions for the Miscellaneous Plan was approximately 12.447% of annual covered payroll for employees hired prior to January 1, 2013, and 12.447% of annual covered payroll for employees hired after January 1, 2013.

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

Valuation Date	Accrued Liability	Market Value of Assets	Unfunded Liability	Funded Ratio	Annual Covered Payroll
06/30/16	$1,295,862,000	$ 881,703,000	$414,159,000	68.0%	$117,138,000
06/30/17	1,361,536,000	957,141,000	404,395,000	70.3	120,748,000
06/30/18	1,455,035,000	1,014,034,000	441,001,000	69.7	120,194,000
06/30/19	1,502,706,000	1,057,123,000	445,583,000	70.3	124,366,000
06/30/20	1,543,927,000	1,084,188,000	459,739,000	70.2	124,700,000

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

The PERS Board adopted a new amortization policy effective with the June 30, 2019 actuarial valuation. The new policy shortens the period over which actuarial gains and losses are amortized from 30 years to 20 years with the payments computed using a level dollar amount. In addition, the new policy removes the five-year ramp-up and ramp-down on unfunded accrued liability bases attributable to assumption changes and non-investment gains/losses. The new policy removes the five-year ramp-down on investment gains/losses. These changes will apply only to new unfunded accrued liability bases established on or after June 30, 2019.

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

The table below sets forth certain information regarding the electric utility's portion of the City's required contributions to its CalPERS Miscellaneous Plan for the Fiscal Years ended June 30, 2017 through June 30, 2021, which amounts were paid in full by the Electric System in each of such fiscal years. The amount budgeted for the electric utility's allocated portion of the City's required contributions to its CalPERS Miscellaneous Plan for Fiscal Year 2021-22 is $11,013,000.

City of Anaheim
Schedule of Electric Utility Pension Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2016-17	$7,159,000	$7,159,000	--	27.58%
2017-18	7,621,000	7,621,000	--	28.93
2018-19	9,005,000	9,005,000	--	32.83
2019-20	10,285,000	10,285,000	--	36.19
2020-21	11,089,000	11,089,000	--	41.49

Source: Anaheim.

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

The table below summarizes certain information relating to the electric utility fund's proportionate share of the Net Pension Liability of the City's Miscellaneous Plan for the measurement periods ended June 30, 2016 through June 30, 2020 (as reported in the City's electric utility fund audited financial statements as of the succeeding fiscal year). The electric utility's proportion of the Net Pension Liability was based on a projection of its long-term share of contributions to the pension plan relative to the projected contributions of all participating funds of the City.

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

Measurement Period[(1)]	Proportionate Share of the Net Pension Liability[(2)]	Electric Utility Share of the Net Pension Liability[(2)]	Net Position as a % of Share of Total Pension Liability	Share of Net Pension Liability as a % of Its Covered Payroll
2015-16	21.5200%	$77,861,000	70.95%	324.79%
2016-17	21.5140	91,561,000	69.27	352.74
2017-18	21.2297	87,747,000	71.03	333.14
2018-19	22.2088	94,322,000	71.33	343.89
2019-20	22.2428	98,035,000	71.16	344.91

(1) Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date.
(2) Reflects the electric utility's share of the City's Miscellaneous Plan Net Pension Liability of $361,805,000, $425,587,000, $413,322,000, $424,705,000 and $440,748,000 for the five Fiscal Year measurement periods of 2015-16, 2016-17, 2017-18, 2018-19 and 2019-20, respectively.
Source: Anaheim.

Retiree Health Benefits. In addition to the defined benefit pension plan described above, the City also maintains a program providing "other post-employment benefits" ("OPEB") to eligible retirees, including health care and disability coverage and death benefits. The City made significant changes to its OPEB program during Fiscal Year ended June 30, 2006. For City employees hired prior to January 1, 1996 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the

IBEW), the length of service credit was frozen for all employees eligible for the benefit. Length of service, a factor in determining the amount of the benefit earned, will not accrue beyond December 31, 2005. Employees hired on or after January 1, 1996 (other than those represented by the Anaheim Police Association or the Anaheim Fire Association) are no longer eligible for City funding of all or a portion of post-employment medical benefits. For City employees represented by the IBEW who had not retired as of October 15, 2005, medical benefits only for future retirees are to be provided through a trust established by the IBEW. Benefits are determined by the trustees of the trust and the City's liability is limited to specified percentages of employee pay.

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

Based on eligibility status, retirees may participate in any health plan made available to active City employees. The City has several plans with different contribution levels and benefit provisions. The City's contributions vary up to 100% of annual premium cost, depending on the employee's Medicare eligibility, year of hire, age and employee group. At June 30, 2019, 1,329 retirees or surviving spouses met the various eligibility requirements and were receiving medical benefits.

The City's contributions toward the cost of its OPEB program are generally advance funded on an actuarial basis to a dedicated reserve, but annual contributions are not required. To pre-fund OPEB liabilities, the City participates in the California Employers' Retiree Benefit Trust, an agent multiple employer plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions that are administered by CalPERS. As of the actuarial valuation date of July 1, 2020, the unfunded liability for the City's OPEB program was $160,100,000, or 37.91% funded.

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

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

City contributions to the OPEB Plan occur as benefits are paid to retirees or contributions to the OPEB Trust. The City contributes an amount not less than the annual actuarially determined contribution measured in accordance with the parameters of GASB No. 75. The table below sets forth certain information regarding the electric utility's allocated share of the City's annual contributions to the OPEB Plan for the Fiscal Years ended June 30, 2019 through June 30, 2021, including the relation of such contributions to the actuarially determined contribution amount for such fiscal year.

City of Anaheim
Schedule of Electric Utility OPEB Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2018-19	$2,109,000	$2,109,000	--	7.64%
2019-20	2,153,000	2,153,000	--	7.86
2020-21	1,773,000	2,048,000	(275,000)	8.04

Source: Anaheim.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the City Net OPEB Liability for the measurement periods ended June 30, 2019 and June 30, 2020 (as reported in the City's electric utility fund audited financial statements as of the succeeding fiscal year).

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

Measurement Period[(1)]	Proportionate Share of the Net OPEB Liability[(2)]	Electric Utility Share of the Net OPEB Liability[(2)]	Net Position as a % of Share of Total OPEB Liability	Share of Net OPEB Liability as a % of Its Covered Payroll
2018-19	13.1411	21,224,000	37.15	76.93
2019-20	13.0617	20,912,000	37.91	76.36

(1) Measured using actuarial valuation as of the measurement date.
(2) Reflects the electric utility's share of the City's Net OPEB Liability of $161,507,000 and $160,100,000 for the fiscal year measurement periods of 2018-19 and 2019-20, respectively.

Source: Anaheim.

Additional information regarding the City's retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Notes 10 and 11 and the Required Supplementary Information to the City's audited financial statements included in the City's annual comprehensive financial report for the Fiscal Year ended June 30, 2021. See APPENDIX B – "AUDITED FINANCIAL STATEMENTS OF THE ANAHEIM ELECTRIC UTILITY FUND FOR THE FISCAL YEAR ENDED JUNE 30, 2021."

Litigation Affecting the Electric System

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

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

There is currently ongoing litigation challenging the City's electric rates. The rate litigation and certain of the other ongoing proceedings involving City electric resources are described below.

Lawsuit Challenging Electric Rates. On October 3, 2017 and November 2, 2018, the City was served with two class action lawsuits on behalf of an Electric System customer and a class of others similarly situated for a tax refund and that the City cease its imposition and collection of electric utility charges based on its current rate structure until it obtains voter approval with respect to its electric utility rates. The court instructed Plaintiff to file a revised complaint in the 2017 action that combines the allegations and claims of both the 2017 and 2018 lawsuits without prejudice to either party's existing rights. On October 28, 2019, the court issued an order requiring Plaintiff to file and serve a Second Amended and First Supplemental Complaint, and on November 19, 2019, Plaintiff served the City with the same to which the City filed a response on December 17, 2019. On June 8, 2020, the court certified the class.

The lawsuit generally alleges that the City's electric utility rates are taxes under Article XIIIC of the California Constitution. Article XIIIC imposes a majority voter approval requirement on local governments such as the City with respect to certain fees and charges for general purposes, and a two-thirds voter approval requirement with respect to certain fees and charges for special purposes. As amended by the passage of Proposition 26 by the State electorate at the November 2, 2010 election, Article XIIIC applies by its terms to any levy, charge or exaction imposed, increased or extended by a local government on or after November 3, 2010. Article XIIIC, as amended, deems any such levy, charge or fee to be a "tax," requiring voter approval unless it comes within one of the listed exceptions. Article XIIIC expressly excludes from its definition of a "tax," among other things, a charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product. According to the lawsuit, no exception found within Article XIIIC would relieve the City from the voting requirement. The Plaintiff is asking the court to find the City in violation of Article XIIIC and enjoin the City from continuing to impose and collect its electric rates based on its current rate structure until it obtains voter approval. The Plaintiff is seeking a refund, on behalf of herself and a class of all others similarly situated, of the electric utility charges billed and paid. A number of lawsuits making similar claims have been filed against public agencies in the State of California. On October 8, 2021, the Orange County Superior Court entered judgment for the City. The Plaintiff appealed this decision. As Article XIIIC is subject to interpretation by California courts, the City is unable to predict the outcome of the appeal at this time.

COVID-19 Risks

The COVID-19 pandemic has impacted the world since early 2020 and continues to influence business operation, schools, and everyday life. Public health orders by State and local authorities restricted the movement of residents outside their homes, limited the types of businesses that can operate, and imposed operating conditions. These orders caused the widespread disruption of daily activities, including the closure or halting of schools, dine-in restaurants, bars, gyms, movie theatres and other entertainment venues, certain government buildings, indoor services for places of worship, and other gathering places. Subsequently, a gradual re-opening of various sectors commenced. As a provider of essential services, the City started a phased reopening of City facilities with limited operating hours and a strong emphasis on the health and safety of City employees as well as those visiting City facilities. However, after a round of business re-openings in May and June, the number of COVID-19 cases rose again across California, prompting the State to reissue orders closing certain businesses and the indoor operations of others. These orders included additional restrictions in a number of counties under active monitoring by the State, including Orange County. Public health orders to address the pandemic may be imposed, modified, lifted, or reinstated, from time to time, as the pandemic continues.

While APU has adjusted its work schedules and staffing to address public health orders, essential personnel remain in their positions, as permitted by the public health orders, and Electric System operations have continued without disruption.

Since the start of the pandemic, APU has implemented a number of measures to assist residential and commercial customers in managing their utility bills, including suspension of penalties, fees, and service shutoffs; deferment of payments; and the ability to pay by credit card. Additionally, APU offers residential customers bill credits from the Low Income Home Energy Assistance Program that includes supplemental funds appropriated under the Coronavirus Aid, Relief, and Economic Security (CARES) Act, and additional bill credits up to $250 for residential customers who are unable to pay their utility bill due to COVID-19 impacts. These measures are on-going and may be modified, lifted, or enhanced based on the level of COVID-19 impacts.

To help offset the reduction in revenue and potential changes in operating and maintenance costs, the Electric System is continuously reviewing expenditures in an effort to minimize the impact of COVID-19 on customers, while maintaining the Electric System's strong financial position. Because of an increase in accounts past due 60 days or more, APU has also explored state and federal programs to offset financial impacts stemming from the pandemic, including the California Arrearages Payment Program which provide utility bill assistance that can be directly applied to past due balances.

The City is unable to predict (i) the duration or extent of the COVID-19 outbreak; (ii) to what extent the pandemic, government responses to the pandemic and resulting disruptions to the local, State, national or global economy may adversely affect manufacturing or supply chains, the operations and maintenance of the Electric System and the revenues of the Electric System; (iii) to what extent APU may provide additional deferrals, forbearances, adjustments or other relief to its customers or changes to its billing and collection procedures or what future actions may be taken or required by other governmental authorities to respond to the pandemic; (iv) to what extent the increased unemployment and other severe economic disruption caused by the pandemic will impair the ability of APU customers to pay their bills, including bills for services provided by the Anaheim Electric System; or (v) the magnitude of the adverse impacts that any of the foregoing may have on the finances and operations of the Electric System. The restrictions and limitations related to COVID-19, and the current upheaval to the local, state, national and global economies may be prolonged, thereby adversely affecting Electric System revenues.

The financial information and operating data contained in this Appendix A includes dates and periods prior to the economic impact of the Pandemic and measures instituted to slow it. Accordingly, information and data from such earlier dates and periods are not necessarily indicative of the current financial condition or future prospects of the Anaheim Electric System.

DEBT SERVICE REQUIREMENTS FOR 2022 SERIES A AND B BONDS (Accrual Basis)

(in thousands (000))

Year Ending July 1,	2022 Series A (Tax-Exempt)				2022 Series B (Federally Taxable)				2022 Series A and B Bonds			
	Principal	Interest	Less: Capitalized Interest [1]	Total	Principal	Interest	Less: Capitalized Interest [1]	Total	Principal	Interest	Less: Capitalized Interest [1]	Total
2022	–	$ 4,937	($4,937)	–	–	$ 418	($ 418)	–	–	$ 5,356	($5,356)	–
2023	–	36,275	(36,275)	–	–	3,073	(3,073)	–	–	39,348	(39,348)	–
2024	–	36,275	(36,275)	–	–	3,073	(3,073)	–	–	39,348	(39,348)	–
2025	–	36,275	(36,275)	–	–	3,073	(3,073)	–	–	39,348	(39,348)	–
2026	$ 22,280	36,275	–	$ 58,555	$ 2,120	3,073	–	$ 5,193	$ 24,400	39,348	–	$ 63,748
2027	23,395	35,161	–	58,556	2,190	2,999	–	5,189	25,585	38,160	–	63,745
2028	24,565	33,991	–	58,556	2,270	2,919	–	5,189	26,835	36,910	–	63,745
2029	25,795	32,763	–	58,558	2,355	2,833	–	5,188	28,150	35,596	–	63,746
2030	27,085	31,473	–	58,558	2,450	2,743	–	5,193	29,535	34,216	–	63,751
2031	28,435	30,119	–	58,554	2,545	2,648	–	5,193	30,980	32,766	–	63,746
2032	29,860	28,697	–	58,557	2,645	2,544	–	5,189	32,505	31,241	–	63,746
2033	31,350	27,204	–	58,554	2,755	2,434	–	5,189	34,105	29,638	–	63,743
2034	32,920	25,637	–	58,557	2,875	2,316	–	5,191	35,795	27,952	–	63,747
2035	34,565	23,991	–	58,556	3,005	2,188	–	5,193	37,570	26,178	–	63,748
2036	36,295	22,262	–	58,557	3,140	2,049	–	5,189	39,435	24,312	–	63,747
2037	37,745	20,811	–	58,556	3,290	1,902	–	5,192	41,035	22,712	–	63,747
2038	39,635	18,923	–	58,558	3,445	1,744	–	5,189	43,080	20,667	–	63,747
2039	41,615	16,942	–	58,557	3,630	1,563	–	5,193	45,245	18,504	–	63,749
2040	43,695	14,861	–	58,556	3,820	1,372	–	5,192	47,515	16,233	–	63,748
2041	45,880	12,676	–	58,556	4,020	1,172	–	5,192	49,900	13,848	–	63,748
2042	48,175	10,382	–	58,557	4,230	960	–	5,190	52,405	11,342	–	63,747
2043	50,585	7,973	–	58,558	4,450	738	–	5,188	55,035	8,712	–	63,747
2044	53,110	5,444	–	58,554	4,685	505	–	5,190	57,795	5,949	–	63,744
2045	55,770	2,789	–	58,559	4,930	259	–	5,189	60,700	3,047	–	63,747
Total	$732,755	$552,133	($113,762)	$1,171,127	$64,850	$48,599	($9,638)	$103,811	$797,605	$600,732	($123,400)	$1,274,938

(1) Capitalized interest through 7/1/2025.

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APPENDIX H

CONTINUING DISCLOSURE RESOLUTION

RESOLUTION NO. IPA-2022-013

MASTER RESOLUTION (2022) AS TO THE PROVISION OF CERTAIN CONTINUING DISCLOSURE INFORMATION WITH RESPECT TO CERTAIN DESIGNATED SERIES OF IPA BONDS

WHEREAS, concurrently with its adoption of this resolution, the Board of Directors (the "Board") of Intermountain Power Agency, a political subdivision of the State of Utah ("IPA"), is authorizing the issuance of $732,755,000 in aggregate principal amount of IPA's Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 in aggregate principal amount of IPA's Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds") pursuant to a resolution of IPA adopted on September 28, 1978, entitled "Power Supply Revenue Bond Resolution", as supplemented, amended and restated from time to time, including as supplemented by a resolution of IPA supplemental thereto adopted on the date of adoption of this resolution entitled "Sixty-First Supplemental Power Supply Revenue Bond Resolution" relating to the 2022 Series A and B Bonds (such Power Supply Revenue Bond Resolution, as from time to time supplemented, amended and restated, being herein called the "Bond Resolution"); and

WHEREAS, the Rule (as defined in Section 1 hereof) requires, for certain issues of municipal securities, that the participating underwriters (as defined in the Rule) for such securities reasonably determine that the issuer of such securities or certain "obligated persons" (as defined in the Rule) has or have undertaken to provide certain continuing disclosure information as required by the Rule; and

WHEREAS, IPA may hereafter issue one or more additional Series of Bonds under (and as defined in) the Bond Resolution and intends that this Master Disclosure Resolution apply to each such additional Series of Bonds if the Board elects to cause this Master Disclosure Resolution to apply to such Series; and

WHEREAS, the Board hereby finds and determines that it is necessary that it adopt this Master Disclosure Resolution (a) to effectuate the agreement between IPA and the Participating Underwriters for the 2022 Series A and B Bonds and (b) in connection with the authorization and sale of the Covered Bonds described in clause (b) of the definition thereof set forth in Section 1 hereof, in order to assist the Participating Underwriter(s) thereof to comply with the Rule.

NOW, THEREFORE, be it resolved by the Board as follows:

SECTION 1. Definitions. In addition to the definitions set forth in the Bond Resolution, which apply to any capitalized term used in this Master Disclosure Resolution, unless otherwise defined in this Master Disclosure Resolution, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report provided by IPA pursuant to, and as described in, Sections 3 and 4 of this Master Disclosure Resolution.

"Audited Financial Statements" shall mean:

a. with respect to IPA, IPA'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 IPA 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 from time to time (or such other accounting principles as may be applicable to LADWP in the future pursuant to applicable law); and

c. 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 Covered Bonds through nominees or depositories (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 under the Rule of this Master Disclosure Resolution.

"Covered Bonds" shall mean each of the following:

a. the 2022 Series A and B Bonds; and

b. each additional Series of Bonds issued by IPA after the date of adoption of this Master Disclosure Resolution as to which the Board has specified, by resolution, that this Master Disclosure Resolution shall apply.

"Dissemination Agent" shall mean any person or entity appointed by IPA and which has entered into a written agreement with IPA pursuant to which such person or entity agrees to perform the duties and obligations of Dissemination Agent under this Master Disclosure Resolution.

"Exchange Act" shall mean the Securities Exchange Act of 1934, as the same may be amended from time to time.

"Financial Obligation" shall mean, for purposes of the Listed Events set out in Section 5(a)(x) and Section (5)(b)(viii), a (i) debt obligation; (ii) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (iii) guarantee of (i) or (ii). The term "Financial Obligation" shall not include municipal securities (as defined in the Exchange Act) as to which a final official statement (as defined in the Rule) has been provided to the MSRB consistent with the Rule.

"Final Official Statement" shall mean: (i) with respect to the 2022 Series A and B Bonds, the Official Statement of IPA dated April 28, 2022 relating to such Bonds; and (ii) with respect to all other Series of Covered Bonds, the final official statement prepared and delivered by IPA with respect thereto, in each of the cases referenced in the immediately preceding clauses (i) and (ii), as such official statements are amended, supplemented or updated.

"Listed Events" shall mean any of the events listed in Section 5(a) or 5(b) of this Master Disclosure Resolution.

"Master Disclosure Resolution" shall mean this resolution, as the same may be amended or supplemented from time to time in accordance with the provisions hereof.

"MSRB" shall mean the Municipal Securities Rulemaking Board established in accordance with the provisions of Section 15B(b)(1) of the Exchange Act 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 https://emma.msrb.org.

"Participating Underwriter" shall mean, with respect to each Series of Covered Bonds, any of the original underwriters of such Covered Bonds required to comply with the Rule in connection with the offering thereof.

"Rule" shall mean Rule 15c2-12(b)(5) adopted by the SEC under the Exchange Act, together with all interpretive guidance or other official interpretations or explanations thereof that are promulgated by the SEC.

"SEC" shall mean the United States Securities and Exchange Commission.

SECTION 2. Purpose of this Master Disclosure Resolution; Obligated Persons; Master Disclosure Resolution to Constitute Contract.

a. This Master Disclosure Resolution is adopted by IPA for the benefit of the Holders and Beneficial Owners of the Covered Bonds and in order to assist the Participating Underwriter(s) for the Covered Bonds in complying with the Rule.

b. IPA, the Department of Water and Power of The City of Los Angeles ("LADWP") and the City of Anaheim, California ("Anaheim") each are hereby determined by IPA to be "obligated persons" 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 is or will be presented in the respective Final Official Statements); provided, however, that Anaheim's status as an "obligated person" within the meaning of the Rule shall terminate on June 15, 2027, upon the termination of Anaheim's Power Sales Contract with IPA).

c. In consideration of the purchase and acceptance of any and all of the Covered Bonds by those who shall hold the same or shall own beneficial ownership interests therein from time to time, this Master Disclosure Resolution shall be deemed to be and shall constitute a contract between IPA and the Holders and Beneficial Owners from time to time of the Covered Bonds; and the covenants and agreements herein set forth to be performed on behalf of IPA shall be for the benefit of the Holders and Beneficial Owners of any and all of the Covered Bonds.

SECTION 3. Provision of Annual Reports.

a. IPA hereby covenants and agrees that it shall, or shall cause the Dissemination Agent to, not later than nine months after the end of each Fiscal Year (presently, by each March 31; each such date being referred to herein as a "Final Submission Date"), commencing with the report for Fiscal Year 2021-22, provide to the MSRB an Annual Report which is consistent with the requirements of Section 4 of this Master 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 Master 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 IPA, LADWP or Anaheim changes, IPA shall give notice of such change in the same manner as for a Listed Event under Section 5(d).

b. Not later than fifteen (15) business days prior to each Final Submission Date (each such date being referred to herein as a "Preliminary Submission Date"), IPA 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 IPA to determine if IPA is in compliance with subsection (a).

c. If IPA or the Dissemination Agent (if any), as the case may be, has not furnished an Annual Report to the MSRB by a Final Submission Date, IPA or the Dissemination Agent, as applicable, shall notify the MSRB to that effect.

d. IPA (or, in the event that IPA shall appoint a Dissemination Agent hereunder, the Dissemination Agent) shall file the Annual Report with the MSRB on or before the Final Submission Date. In addition, if IPA shall have appointed a Dissemination Agent hereunder, the Dissemination Agent shall file a report with IPA certifying that the Annual Report has been provided pursuant to this Master Disclosure Resolution and stating the date it was provided to the MSRB.

SECTION 4. Content of Annual Reports. IPA's Annual Report shall contain or include by reference the following:

a. The Audited Financial Statements. If any Audited Financial Statements are not available by the Final Submission Date, the Annual Report shall contain unaudited financial statements for IPA, LADWP and/or Anaheim, as applicable, in a format similar to the audited financial statements most recently prepared for such 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 or included by specific reference in the Final Official Statement for each Series of Covered Bonds then Outstanding relating to the following:

i. IPA's indebtedness;

ii. the description of security and sources of payment for such Series of Covered Bonds provided by the Bond Resolution, the Power Sales Contracts, the Excess Power Sales Agreement, the Renewal Power Sales Contracts and the Agreement for Sale of Renewal Excess Power referred to in the Final Official Statement;

iii. the financial results of IPA's operations;

iv. IPA's financing program;

v. IPA's annual budget; and

vi. the operating results of the Project.

c. Updated versions of the type of information for LADWP contained or included by specific reference in the Final Official Statement for each Series of Covered Bonds then Outstanding relating to the following:

i. the description of operations and the summary of operating results of LADWP's Power System; and

ii. the summary of financial results of LADWP's Power System.

d. For so long as Anaheim remains an obligated person with respect to the Covered Bonds of any Series, updated versions of the type of information for Anaheim contained or included by specific reference in the Final Official Statement for each Series of Covered Bonds then Outstanding relating to the following:

i. the description of operations and the summary of operating results of the Anaheim Public Utilities Department's electric system (the "Anaheim Electric System"); and

ii. the summary of financial results of the Anaheim Electric System.

Any or all of the items listed above may be included by specific reference to other documents, including annual reports of IPA, LADWP or Anaheim or official statements relating to debt or other securities issues of IPA, LADWP, Anaheim or other entities, which have been submitted to the MSRB or filed with the SEC pursuant to the Exchange Act. If the document included by reference is a final official statement (as defined in the Rule), it must be available from the MSRB. IPA shall clearly identify each such other document so included by reference.

SECTION 5. Reporting of Significant Events.

a. Pursuant to the provisions of this Section 5(a), IPA 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 any Series of the Covered Bonds not later than ten (10) business days after the occurrence of the event:

i. Principal and interest payment delinquencies;

ii. Unscheduled draws on debt service reserves reflecting financial difficulties;

iii. Unscheduled draws on credit enhancements reflecting financial difficulties;

iv. Substitution of credit or liquidity providers, or their failure to perform;

v. Issuance by the Internal Revenue Service of proposed or final determination of taxability or of a Notice of Proposed Issue (IRS Form 5701 TEB);

vi. Tender offers;

vii. Defeasances;

viii. Rating changes;

ix. Bankruptcy, insolvency, receivership or similar event of the obligated person; or

x. Default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a Financial Obligation of the obligated person, any of which reflect financial difficulties.

Note: for the purposes of the event identified in subparagraph (ix), the event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for an obligated person in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the obligated person, or if such jurisdiction has been assumed by leaving the existing governmental body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person.

b. Pursuant to the provisions of this Section 5(b), IPA 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 any Series of the Covered Bonds, if material, not later than ten (10) business days after the occurrence of the event:

i. Unless described in paragraph 5(a)(v), adverse tax opinions or other material notices or determinations by the Internal Revenue Service with respect to the tax status of the Covered Bonds of such Series or other material events affecting the tax status of the Covered Bonds of such Series;

ii. Modifications to rights of Covered Bond holders;

iii. Unscheduled or contingent Covered Bond calls;

iv. Release, substitution, or sale of property securing repayment of the Covered Bonds;

v. Non-payment related defaults;

vi. The consummation of a merger, consolidation, or acquisition involving an obligated person or the sale of all or substantially all of the assets of the obligated person, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms;

vii. Appointment of a successor or additional trustee or the change of name of a trustee; or

viii. Incurrence of a Financial Obligation of the obligated person, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a Financial Obligation of the obligated person, any of which affect security holders.

c. Whenever IPA obtains knowledge of the occurrence of a Listed Event described in Section 5(b), IPA shall as soon as possible determine if the occurrence of such event is material under applicable federal securities laws.

d. If IPA learns of the occurrence of a Listed Event described in Section 5(a), or determines that knowledge of a Listed Event described in Section 5(b) is material under applicable federal securities laws, IPA shall file a notice of such occurrence with the MSRB within ten (10) business days after the occurrence of the event. Notwithstanding the foregoing, notice of Listed Events described in subsections (a)(vii) and (b)(iii) need not be given under this subsection any earlier than the notice of the underlying event is given to Holders of affected Covered Bonds pursuant to the Bond Resolution.

e. IPA intends to comply with the foregoing notice requirement with respect to the Listed Events described in Section 5(a)(x) and Section 5(b)(viii), as the term "Financial Obligation" is defined in Section 1, with reference to the Rule, any other applicable federal securities laws and the guidance provided by the SEC in Release No. 34-83885 dated August 20, 2018 (the "2018 Release"), and any further amendments or written guidance provided by the SEC or its staff with respect the amendments to the Rule effected by the 2018 Release.

SECTION 6. Format for Filings with MSRB. Any report or filing with the MSRB pursuant to this Master Disclosure Resolution must be submitted in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

SECTION 7. Management's Discussion of Items Disclosed in Annual Reports or as Significant Events. If an item required to be disclosed in IPA's Annual Report under Section 4, or as a Listed Event under Section 5, would be misleading without discussion, IPA 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.

SECTION 8. Termination of Reporting Obligation. IPA's obligations under this Master Disclosure Resolution to the Holders or Beneficial Owners of the Covered Bonds of any Series shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Covered Bonds of such Series. In addition, in the event that the Rule shall be amended, modified or repealed such that compliance by IPA with its obligations under this Master Disclosure Resolution no longer shall be required in any or all respects, then IPA's obligations under this Master Disclosure Resolution shall terminate to a like extent. If either such termination occurs with respect to the Covered Bonds of any Series prior to the final maturity date of such Bonds, IPA shall give notice of such termination in the same manner as for a Listed Event under Section 5(d).

SECTION 9. Dissemination Agent. IPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Master Disclosure Resolution, and may discharge any such Agent, with or without appointing a successor Dissemination Agent.

SECTION 10. Amendment; Waiver.

a. Notwithstanding any other provision of this Master Disclosure Resolution, IPA may, by resolution hereafter adopted, amend this Master Disclosure Resolution, and any provision of this Master Disclosure Resolution may be waived:

i. if such amendment or waiver is supported by an opinion of counsel expert in federal securities laws appointed by IPA to the effect that such amendment or waiver would not, in and of itself, cause the undertakings herein to violate the Rule, taking into account any subsequent change in or official interpretation of the Rule, and

ii. as to any amendment to this Master Disclosure Resolution, the following conditions are complied with:

(1) The amendment may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature, or status of IPA, LADWP or Anaheim, or type of business conducted;

(2) The undertaking, as amended, would have complied with the requirements of the Rule at the respective times of the primary offering of each Series of the Covered Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(3) The amendment does not materially impair the interests of Holders or Beneficial Owners of the Covered Bonds, as determined either by parties unaffiliated with IPA, LADWP or Anaheim (such as bond counsel to IPA), or by approving vote of Holders of the Covered Bonds pursuant to the terms of the Bond Resolution at the time of the amendment.

b. The Annual Report containing the amended operating data or financial information will explain, 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.

SECTION 11. Additional Information. Nothing in this Master Disclosure Resolution shall be deemed to prevent IPA from disseminating, or require IPA to disseminate, any other information, using the means of dissemination set forth in this Master 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 Master Disclosure Resolution. If IPA 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 Master Disclosure Resolution, IPA shall have no obligation under this Master Disclosure Resolution to update such information or include it in any future Annual Report or notice of occurrence of a Listed Event.

SECTION 12. Default.

a. In the event of a failure of IPA to comply with any provision of this Master Disclosure Resolution, any Holder or Beneficial Owner of any Outstanding Covered Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause IPA to comply with its obligations under this Master Disclosure Resolution.

b. Notwithstanding the foregoing, no Holder or Beneficial Owner of the Covered Bonds of any Series shall have the right to challenge the content or adequacy of the information provided pursuant to Sections 3, 4 or 5 of this Master Disclosure Resolution by mandamus, specific performance or other equitable proceedings unless Holders or Beneficial Owners of Covered Bonds of such Series representing at least 25% in aggregate principal amount of the Covered Bonds of such Series shall join in such proceedings.

c. A default under this Master Disclosure Resolution shall not be deemed an Event of Default under the Bond Resolution, and the sole remedies under this Master Disclosure Resolution in the event of any failure of IPA to comply with this Master 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 IPA to comply with this Master Disclosure Resolution.

SECTION 13. Duties, Immunities and Liabilities of Dissemination Agent. Any Dissemination Agent appointed hereunder shall have only such duties as are specifically set forth in this Master Disclosure Resolution, and shall have such rights, immunities and liabilities as shall be set forth in the written agreement between IPA and such Dissemination Agent pursuant to which such Dissemination Agent agrees to perform the duties and obligations of Dissemination Agent under this Master Disclosure Resolution.

SECTION 14. Beneficiaries. This Master Disclosure Resolution shall inure solely to the benefit of IPA, the Dissemination Agent, if any, and the Holders and Beneficial Owners from time to time of the Covered Bonds, and shall create no rights in any other person or entity.

SECTION 15. Governing Law. This Master Disclosure Resolution shall be deemed to be a contract made under the Rule and the laws of the State of Utah, and for all purposes shall be construed and interpreted in accordance with, and its validity governed by, the Rule and the laws of such State.

SECTION 16. Effective Date. This Master Disclosure Resolution shall become effective as to each Series of Covered Bonds upon the date of authentication and delivery of such Series of Covered Bonds.

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Resolution No. IPA-2022-013 approved and adopted April 28, 2022.

INTERMOUNTAIN POWER AGENCY

By: /S/ BLAINE J. HAACKE
Chair, Board of Directors

Secretary's Certificate

Now comes the undersigned Secretary of Intermountain Power Agency ("IPA"), keeper of the records and seal thereof, and certifies that the foregoing is a true and correct copy of the Master Resolution (2022) as to the Provision of Certain Continuing Disclosure Information with Respect to Certain Designated Series of IPA Bonds approved and adopted by the IPA Board of Directors in a meeting of such Board of Directors properly and lawfully called and assembled on April 28 2022, the original of which Resolution has been entered in the official records of IPA under my supervision and is in my official possession, custody and control.

[SEAL]

INTERMOUNTAIN POWER AGENCY

/s/ ERIC LARSEN
Secretary

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APPENDIX I

PROPOSED FORM OF OPINION OF BOND COUNSEL

Upon the delivery of the 2022 Series A and B Bonds, Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, proposes to render its final approving opinion with respect to such Bonds in substantially the following form:

May __, 2022

Board of Directors
Intermountain Power Agency
South Jordan, Utah 84095

Intermountain Power Agency
Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt)
and 2022 Series B (Federally Taxable)

Gentlemen:

We have acted as bond counsel to Intermountain Power Agency (the "Agency"), a political subdivision of the State of Utah, in connection with the issuance of $732,755,000 aggregate principal amount of Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 aggregate principal amount of Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds"), issued pursuant to the provisions of the Utah Interlocal Cooperation Act (constituting Title 11, Chapter 13 of the Utah Code Annotated, 1953, as amended (the "Act")), and under and pursuant to a resolution of the Agency adopted on September 28, 1978 entitled "Power Supply Revenue Bond Resolution," as heretofore supplemented, amended and restated, including as supplemented and amended by a resolution supplemental thereto adopted by the Agency on April 28, 2022 entitled "Sixty-First Supplemental Power Supply Revenue Bond Resolution" (such Power Supply Revenue Bond Resolution, as so supplemented, amended and restated, being herein called the "Resolution"). The 2022 Series A and B Bonds constitute "Bonds" within the meaning of the Resolution. Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Resolution.

The Resolution provides that the 2022 Series A and B Bonds are being issued for the stated purposes of financing and refinancing a portion of the Cost of Acquisition and Construction of the Gas Repowering of the Project, funding a debt service reserve account, funding capitalized interest on the 2022 Series A and B Bonds through July 1, 2025 and paying costs of issuance of the 2022 Series A and B Bonds. The Agency reserves the right to issue additional Bonds on the terms and conditions and for the purposes stated in the Resolution. Under the provisions of the Resolution, all Outstanding Bonds shall rank equally as to security and payment from the Trust Estate.

The Agency has entered into thirty-five separate Power Sales Contracts with the following purchasers (the "Power Purchasers") of capability of the Project: twenty-three municipally owned electric systems in the State of Utah (the "Utah Purchasers"), six rural electric cooperatives rendering electric service in the State of Utah (the "Cooperative Purchasers") and six municipalities in the State of California (the "California Purchasers"). Said Power Sales Contracts have heretofore been amended, including (a) the amendments thereto provided for by the thirty-five separate Amendatory Power Sales Contracts entered into between the Agency and each of the thirty-five Power Purchasers, and (b) the amendments thereto provided for by the thirty-five separate Second Amendatory Power Sales Contracts entered into between the Agency and each of the thirty-five Power Purchasers (the "Second Amendatory Power Sales

Contracts"), the appendices to such Power Sales Contracts have been updated in accordance with the terms of such Power Sales Contracts and such Power Sales Contracts have been revised pursuant to Section 44.1 of such Power Sales Contracts by the Alternative Repowering Revisions (as defined in such Power Sales Contracts) approved by Resolution No. CC-2018-010 of the Intermountain Power Project Coordinating Committee, Resolution No. RCCC-2018-004 of the Intermountain Power Project Renewal Contract Coordinating Committee and Resolution No. IPA-2018-019 of the Agency's Board of Directors on September 24, 2018 (said Power Sales Contracts, as so amended, updated and revised, are herein called the "Power Sales Contracts").

The Agency also has entered into thirty separate Renewal Power Sales Contracts with the following purchasers (the "Renewal Power Purchasers") of capability of the Project from and after June 16, 2027: twenty-one municipally owned electric systems in the State of Utah (the "Utah Renewal Purchasers"), the Cooperative Purchasers and three of the six California Purchasers (the "California Renewal Purchasers"), as the appendices to such Renewal Power Sales Contracts heretofore have been updated in accordance with the terms of such Renewal Power Sales Contracts (said Renewal Power Sales Contracts, as so updated, are herein called the "Renewal Power Sales Contracts").

As bond counsel, we have reviewed certified copies of the Resolution, the Power Sales Contracts and the Renewal Power Sales Contracts; opinions of counsel to the Agency, the Power Purchasers and the Renewal Power Purchasers; the Tax Certificate executed and delivered by the Agency on the date hereof in connection with the issuance of the 2022 Series A Bonds (the "Tax Certificate"); opinions of counsel to the Agency, the Power Purchasers and the Renewal Power Purchasers; certificates of the Agency, the Trustee and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after original delivery of the 2022 Series A and B Bonds on the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after original delivery of the 2022 Series A and B Bonds on the date hereof. Accordingly, this letter speaks only as of its date and is not intended to, and may not, be relied upon or otherwise used in connection with any such actions, events or matters. Our engagement with respect to the 2022 Series A and B Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed (a) the genuineness of all documents and signatures provided to us, (b) the due and legal execution and delivery of all documents provided to us by any parties other than the Agency (except that we did not personally witness the execution and delivery on behalf of the Agency of any of the Power Sales Contracts or any amendment thereto or any of the Renewal Power Sales Contracts so, for purposes of the opinions expressed in paragraphs 4 and 5 below, we have relied solely upon a certificate of the Agency to the effect, among other things, that the Power Sales Contracts and the amendments thereto and the Renewal Power Sales Contracts have been duly executed and delivered on behalf of the Agency) and (c) the validity of all documents provided to us against any parties other than the Agency and, with respect to the Power Sales Contracts, the Power Purchasers and, with respect to the Renewal Power Sales Contracts, the Renewal Power Purchasers. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the fifth paragraph of this letter (except that we have not relied on any such legal conclusions that are to the same effect as the opinions set forth herein). Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolution, the Power Sales Contracts, the Renewal Power Sales Contracts and the Tax Certificate, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the 2022 Series A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the 2022 Series A and B Bonds, the Resolution, the Power Sales Contracts, the Renewal Power Sales Contracts and the Tax Certificate and their

enforceability may be subject to bankruptcy, insolvency, receivership, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against political subdivisions of the State of Utah. We express no opinion with respect to any indemnification, contribution, liquidated damages, penalty (including any remedy deemed to constitute or to have the effect of a penalty), right of set-off, arbitration, choice of law, choice of forum, choice of venue, non-exclusivity of remedies, waiver or severability provisions contained in the foregoing documents. Our services did not include financial or other non-legal advice. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Official Statement of the Agency, dated April 28, 2022, relating to the 2022 Series A and B Bonds or other offering material relating to the 2022 Series A and B Bonds and express no opinion or conclusion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Agency is duly created and validly existing under the provisions of the Act and has the legal right and lawful authority under the Act to acquire and construct the Project and provide for the operation and maintenance thereof.

2. The Agency has the right and power under the Act to adopt the Resolution, and the Resolution has been duly and lawfully adopted by the Agency, is in full force and effect in accordance with its terms and is valid and binding upon the Agency and enforceable in accordance with its terms, and no other authorization for the Resolution is required. The Resolution creates the valid pledges and assignments it purports to create of the Trust Estate and the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Resolution, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

3. The Agency is duly authorized and entitled to issue the 2022 Series A and B Bonds, and the 2022 Series A and B Bonds have been duly and validly authorized and issued by the Agency in accordance with the Constitution and laws of the State of Utah, including the Act, and the Resolution. The 2022 Series A and B Bonds constitute the valid and binding obligations of the Agency as provided in the Resolution, are enforceable in accordance with their terms and the terms of the Resolution and are entitled to the benefits of the Act and the Resolution. Neither the State of Utah nor any political subdivision thereof (other than the Agency) nor any member of the Agency nor any Power Purchaser nor the Project Manager or the Operating Agent under the Construction Management and Operating Agreement shall be obligated to pay the principal of, or interest on, the 2022 Series A and B Bonds and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or of any city or town which is either a member of the Agency or a Power Purchaser or both is pledged to the payment of the principal of, or interest on, the 2022 Series A and B Bonds. No Holder of any 2022 Series A and B Bond or receiver or trustee in connection with the payment of the 2022 Series A and B Bonds shall have any right to compel the State of Utah, any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both to exercise its appropriation or taxing powers.

4. The Agency has the right and power to enter into and carry out its obligations under the Power Sales Contracts and has duly authorized, executed and delivered the Power Sales Contracts which constitute valid and binding agreements of the Agency in accordance with their terms.

5. The Agency has the right and power to enter into and carry out its obligations under the Renewal Power Sales Contracts and has duly authorized, executed and delivered the Renewal

Power Sales Contracts which constitute valid and binding agreements of the Agency in accordance with their terms.

6. Under the Constitution and laws of the State of Utah, each Power Sales Contract with a Utah Purchaser constitutes a valid and binding agreement of the Utah Purchaser party thereto 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 and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any Utah Purchaser or the incumbency of any official or officer thereof, (ii) the charter, by laws or other governing instrument of any Utah Purchaser, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Utah Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any Utah Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Utah Purchaser is a party (other than the proceedings and order in the case of *Murray City v. Brown* (1980) which involved the Power Sales Contract with the Utah Purchaser of Murray City, Utah) or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Utah Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983 opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the Utah Purchasers rendered by legal counsel to the respective Utah Purchasers and, in addition, received from such counsel (a) confirmations of such opinions dated the date hereof and (b) opinions dated December 8, 2015, other than the opinion of counsel to the Utah Purchaser of Heber Light & Power Company, which was dated March 11, 2016, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such Utah Purchaser is a party has been duly authorized, executed and delivered by such Utah Purchaser.

7. Under the Constitution and laws of the State of Utah (or Nevada, in the case of the Cooperative Purchaser organized under the laws of said State, or Wyoming, in the case of the Cooperative Purchaser organized under the laws of said State), each Power Sales Contract with a Cooperative Purchaser constitutes a valid and binding agreement of the Cooperative Purchaser party thereto 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 and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any Cooperative Purchaser or the incumbency of any official or officer thereof, (ii) the articles of incorporation, charter, by laws or other governing instrument of any Cooperative Purchaser, (iii) any local or special acts or any resolution or other proceedings of any Cooperative Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof, (iv) any mortgage, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any Cooperative Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Cooperative Purchaser is a party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Cooperative Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983 opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the Cooperative Purchasers rendered by legal counsel to the respective Cooperative Purchasers and, in addition, received from such counsel (a) confirmations of such opinions dated the date hereof

and (b) opinions dated December 8, 2015, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such Cooperative Purchaser is a party has been duly authorized, executed and delivered by such Cooperative Purchaser.

8. Under the Constitution and laws of the State of California and the respective charters of the California Purchasers, each Power Sales Contract with a California Purchaser constitutes a valid and binding agreement of the California Purchaser party thereto 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 and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any California Purchaser or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of any California Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof (except that we have examined the respective ordinances and resolutions pursuant to which the Power Sales Contracts of the California Purchasers were authorized by the respective California Purchasers), (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any California Purchaser, (iv) any judicial order, judgment or decree in a proceeding to which any California Purchaser 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 which may be or has been required for the authorization, execution, delivery or performance by any California Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983 opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the California Purchasers rendered by legal counsel to the respective California Purchasers and, in addition, received from such counsel (a) confirmations of such opinions dated the date hereof and (b) opinions dated March 11, 2016, other than the opinions of counsel to the California Purchaser of the Department of Water and Power of the City of Los Angeles, which were dated February 26, 2016, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such California Purchaser is a party has been duly authorized, executed and delivered by such California Purchaser.

9. Under the Constitution and laws of the State of Utah, each Renewal Power Sales Contract with a Utah Renewal Purchaser constitutes a valid and binding agreement of the Utah Renewal Purchaser party thereto 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 and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any Utah Renewal Purchaser or the incumbency of any official or officer thereof, (ii) the charter, by laws or other governing instrument of any Utah Renewal Purchaser, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Utah Renewal Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Utah Renewal Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Utah Renewal Purchaser is a party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Utah Renewal Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017, opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the Utah

Renewal Purchasers rendered by legal counsel to the respective Utah Renewal Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof.

10. Under the Constitution and laws of the State of Utah (or Nevada, in the case of the Cooperative Purchaser organized under the laws of said State, or Wyoming, in the case of the Cooperative Purchaser organized under the laws of said State), each Renewal Power Sales Contract with a Cooperative Purchaser constitutes a valid and binding agreement of the Cooperative Purchaser party thereto 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 and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any Cooperative Purchaser or the incumbency of any official or officer thereof, (ii)the articles of incorporation, charter, by laws or other governing instrument of any Cooperative Purchaser, (iii) any local or special acts or any resolution or other proceedings of any Cooperative Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iv) any mortgage, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Cooperative Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Cooperative Purchaser is a party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Cooperative Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017, opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the Cooperative Purchasers rendered by legal counsel to the respective Cooperative Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof.

11. Under the Constitution and laws of the State of California and the respective charters of the California Renewal Purchasers, each Renewal Power Sales Contract with a California Renewal Purchaser constitutes a valid and binding agreement of the California Renewal Purchaser party thereto 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 and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any California Renewal Purchaser or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of any California Renewal Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any California Renewal Purchaser, (iv) any judicial order, judgment or decree in a proceeding to which any California Renewal Purchaser 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 which may be or has been required for the authorization, execution, delivery or performance by any California Renewal Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017, opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the California Renewal Purchasers rendered by legal counsel to the respective California Renewal Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof.

12. Interest on the 2022 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986. Interest on the 2022

Series A Bonds is not a specific preference item for purposes of the federal alternative minimum tax.

13. Interest on the 2022 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986.

14. Interest on the 2022 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah.

Except as stated in paragraphs 12, 13 and 14 hereof, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the 2022 Series A and B Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

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Intermountain Power Agency • Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) and 2022 Series B (Federally Taxable)

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