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

In the opinion of Special Counsel, interest on the Series 2024 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). See "TAX MATTERS – Certain U.S. Federal Income Tax Considerations" herein. In the further opinion of Special Counsel, interest on the Series 2024 Bonds is exempt from State of Oregon personal income taxes. See "TAX MATTERS – Certain State of Oregon Income Tax Considerations" herein.

Climate Bond Certified Aligned

kestrel

$76,020,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 9)
Series 2024 (Federally Taxable) (Green Bonds – Climate Bond Certified)

Dated: Date of Delivery

The Series 2024 Bonds will be special obligations of the Port of Morrow, Oregon (the "Issuer") payable solely from the trust estate pledged therefor which trust estate includes amounts derived from rental payments paid to the Issuer pursuant to a Lease-Purchase Agreement, dated June 13, 2024 (the "Lease-Purchase Agreement"), between the Issuer and the United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

Bonneville's payments under the Lease-Purchase Agreement will be made solely from the Bonneville Fund. The Lease-Purchase Agreement provides that Bonneville's obligation to pay the rental payments and all amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project financed with the proceeds of the Series 2024 Bonds is operating or operable. Bonneville's payment obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America. See "THE ISSUER – Limited Obligation."

The Series 2024 Bonds are being issued for the principal purpose of financing for the costs of acquisition of certain transmission facilities to be owned by the Issuer and leased to Bonneville pursuant to the Lease-Purchase Agreement. See "PURPOSE OF ISSUANCE AND USE OF PROCEEDS."

The Series 2024 Bonds will bear interest from the date of their issuance, payable on September 1, 2024 and semi-annually thereafter on March 1 and September 1 of each year. The Series 2024 Bonds will be issued in fully registered form and will be initially registered only in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"), which will act as securities depository for the Series 2024 Bonds. Individual purchases in principal amounts of $5,000 or multiples thereof will be made only through the book-entry-only system maintained by DTC through brokers and dealers who are, or act through, DTC Participants. The purchasers of the Series 2024 Bonds will not receive certificates representing their interest in the Series 2024 Bonds. Ownership interests in the Series 2024 Bonds will be shown on, and transfers of Series 2024 Bonds will be effected only through, records maintained by DTC and its participants. Payments of principal of, premium, if any, and interest on the Series 2024 Bonds will be made to owners by DTC through its participants.

The Trustee for the Series 2024 Bonds is U.S. Bank Trust Company, National Association.

The Series 2024 Bonds are subject to redemption prior to maturity as described herein.

The Series 2024 Bonds have been designated as "Green Bonds – Climate Bond Certified." Kestrel has provided an independent external review and opinion that the Series 2024 Bonds conform with the Climate Bonds Standard (Version 4.0), and therefore qualify for Climate Bonds designation. See "DESIGNATION OF SERIES 2024 BONDS AS GREEN BONDS – CLIMATE BOND CERTIFIED" herein and Appendix F "VERIFIER'S REPORT" hereto for more information.

The Series 2024 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of the proceedings authorizing the Series 2024 Bonds by Orrick, Herrington & Sutcliffe LLP, and to certain other conditions. Certain legal matters will be passed upon for the Issuer by Monahan, Grove & Tucker, Milton-Freewater, Oregon, and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York. The Series 2024 Bonds are expected to be delivered through the facilities of DTC on or about June 13, 2024.

Wells Fargo Securities

BofA Securities **TD Securities**

June 6, 2024

$76,020,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 9)
Series 2024 (Federally Taxable) (Green Bonds – Climate Bond Certified)

Year (September 1)	Amount	Interest Rate	Yield	Price	CUSIP No.†
2030	$26,940,000	4.819%	4.819%	100.000	73474TAV2
2031	27,945,000	4.839	4.839	100.000	73474TAW0
2032	21,135,000	4.887	4.887	100.000	73474TAX8

† The CUSIP number is provided by CUSIP Global Services, managed on behalf of the American Bankers Association by FactSet Research Systems Inc. The CUSIP number is not intended to create a database and does not serve in any way as a substitute for CUSIP service. CUSIP numbers are provided for convenience and reference only, and are subject to change. Neither the Issuer nor the Underwriters take responsibility for the accuracy of the CUSIP number.

The information contained in this Official Statement has been obtained from the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") and in certain limited instances from the Port of Morrow, Oregon (the "Issuer") and other sources which are deemed to be reliable. This Official Statement is submitted in connection with the sale of the securities referred to herein, and may not be reproduced or be used, in whole or in part, for any other purpose. The delivery of this Official Statement at any time does not imply that the information herein is correct as of any time subsequent to its date.

No dealer, salesman or any other person has been authorized by the Issuer or Wells Fargo Bank, National Association and the other Underwriters (collectively the "Underwriters") to give any information or to make any representations other than as contained in this Official Statement in connection with the offering described herein and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. This Official Statement does not constitute an offer of any securities, other than those described on the cover page, or an offer to sell or a solicitation of an offer to buy in any jurisdiction in which it is unlawful to make such offer, solicitation or sale.

The Underwriters have provided the following sentence for inclusion in this Official Statement. The Underwriters have reviewed the information in the 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 Issuer makes no representation as to the accuracy or completeness of any information in this Official Statement and takes no responsibility for its contents, other than the information relating to the Issuer under the headings "THE ISSUER," "VALIDATION," and "LEGAL MATTERS."

This Official Statement contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "estimate," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. A number of important factors affecting Bonneville's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements. Bonneville does not plan to issue updates or revisions to the forward-looking statements.

The Series 2024 Bonds will not be registered under the Securities Act of 1933, as amended, in reliance upon an exemption contained in such act. The Series 2024 Bonds have not been registered or qualified under the securities laws of any state. The Series 2024 Bonds have not been recommended by any federal, state or foreign securities commission or regulatory authority, and the foregoing authorities have neither reviewed nor confirmed the accuracy of this document.

No action has been taken by the Issuer that would permit a public offering of the Series 2024 Bonds or possession or distribution of the Official Statement or any other offering material in any foreign jurisdiction where action for that purpose is required. Accordingly, each of the Underwriters has agreed that any Bonds offered or sold outside of the United States of America by the Underwriters will be offered and sold in compliance with the applicable laws, rules and regulations of the jurisdiction in which they are offered and sold, and the Underwriters will obtain any consent, approval or permission required by it for the offer or sale by it of the Series 2024 Bonds under the laws and regulations in force in any foreign jurisdiction to which it is subject or in which it makes such offers or sales, and the Issuer shall have no responsibility therefor.

References to website addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader's convenience. Unless specified otherwise, such websites and the information or links contained therein are not incorporated into, and are not part of, this official statement for purposes of, and as that term is defined in, Rule 15c2-12 under the Securities Exchange Act of 1934, of the United States Securities and Exchange Commission, as amended, and in effect on the date hereof ("Rule 15c2-12").

Despite the Verifier's Report being provided by Kestrel, it should be noted that there is currently no clearly defined regulatory definition applicable to "green bonds." No assurance can be given that such a clear definition will develop over time, or that, if developed, it will include the projects to be financed or refinanced with the proceeds of the Series 2024 Bonds. Accordingly, no assurance is or can be given to investors that any uses of the proceeds of the Series 2024 Bonds will meet investor expectations regarding such "green" or other equivalently labeled performance objectives or that any adverse environmental and other impacts will not occur during the construction or operation of projects to be financed with Series 2024 Bonds proceeds.

The term "Green Bonds" is neither defined in nor related to the Resolution, and its use herein is for identification purposes only and is not intended to provide or imply that a holder of the Series 2024 Bonds is entitled to any additional security other than as provided in the Resolution. The Issuer has not agreed and will have no obligation to provide any reporting specific to the use of proceeds of the Series 2024 Bonds.

INFORMATION CONCERNING OFFERING RESTRICTIONS IN CERTAIN JURISDICTIONS OUTSIDE THE UNITED STATES

THE ISSUER MAKES NO REPRESENTATION AS TO THE ACCURACY, COMPLETENESS OR ADEQUACY OF THE INFORMATION UNDER THIS CAPTION. REFERENCES UNDER THIS CAPTION TO "BONDS" OR "SECURITIES" MEAN THE SERIES 2024 BONDS OFFERED HEREBY. THESE LEGENDS ARE BEING PROVIDED SOLELY FOR THE CONVENIENCE OF THE UNDERWRITERS. COMPLIANCE WITH ANY RULES OR RESTRICTIONS OF ANY JURISDICTION RELATING TO THE OFFERING, SOLICITATION AND/OR SALE OF THE BONDS IS THE RESPONSIBILITY OF THE UNDERWRITERS AND NEITHER THE ISSUER NOR BONNEVILLE SHALL HAVE ANY RESPONSIBILITY OR LIABILITY IN CONNECTION THEREWITH.

IN CONNECTION WITH OFFERINGS AND SALES OF THE BONDS, NO ACTION HAS BEEN TAKEN BY THE ISSUER THAT WOULD PERMIT A PUBLIC OFFERING OF THE BONDS, OR POSSESSION OR DISTRIBUTION OF ANY INFORMATION RELATING TO THE PRICING OF THE BONDS, THIS OFFICIAL STATEMENT OR ANY OTHER OFFERING OR PUBLICITY MATERIAL RELATING TO THE BONDS, IN ANY NON-U.S. JURISDICTION WHERE ACTION FOR THAT PURPOSE IS REQUIRED.

NOTICE TO PROSPECTIVE INVESTORS IN CANADA

NO PROSPECTUS HAS BEEN FILED WITH ANY SECURITIES COMMISSION OR SIMILAR REGULATORY AUTHORITY IN CANADA IN CONNECTION WITH THE OFFERING OF THE BONDS. NO SECURITIES COMMISSION OR SIMILAR REGULATORY AUTHORITY IN CANADA HAS REVIEWED OR IN ANY WAY PASSED UPON THIS OFFICIAL STATEMENT OR THE MERITS OF THE BONDS AND ANY REPRESENTATION TO THE CONTRARY IS AN OFFENCE. THIS OFFICIAL STATEMENT IS NOT, AND UNDER NO CIRCUMSTANCES IS TO BE CONSTRUED AS, AN ADVERTISEMENT OR A PUBLIC OFFERING OF THE BONDS IN CANADA.

THE BONDS MAY BE SOLD IN CANADA ONLY TO PURCHASERS PURCHASING, OR DEEMED TO BE PURCHASING, AS PRINCIPAL THAT ARE ACCREDITED INVESTORS, AS DEFINED IN NATIONAL INSTRUMENT 45-106 PROSPECTUS EXEMPTIONS OR SUBSECTION 73.3(1) OF THE SECURITIES ACT (ONTARIO), AND ARE PERMITTED CLIENTS, AS DEFINED IN NATIONAL INSTRUMENT 31-103 REGISTRATION REQUIREMENTS, EXEMPTIONS AND ONGOING REGISTRANT OBLIGATIONS. ANY RESALE OF THE BONDS MUST BE MADE IN ACCORDANCE WITH AN EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE PROSPECTUS REQUIREMENTS OF APPLICABLE SECURITIES LAWS.

SECURITIES LEGISLATION IN CERTAIN PROVINCES OR TERRITORIES OF CANADA MAY PROVIDE A PURCHASER WITH REMEDIES FOR RESCISSION OR DAMAGES IF THIS OFFICIAL STATEMENT (INCLUDING ANY AMENDMENT THERETO) CONTAINS A MISREPRESENTATION, PROVIDED THAT THE REMEDIES FOR RESCISSION OR DAMAGES ARE EXERCISED BY THE PURCHASER WITHIN THE TIME LIMIT PRESCRIBED BY THE SECURITIES LEGISLATION OF THE PURCHASER'S PROVINCE OR TERRITORY. THE PURCHASER SHOULD REFER TO ANY APPLICABLE PROVISIONS OF THE SECURITIES LEGISLATION OF THE PURCHASER'S PROVINCE OR TERRITORY FOR PARTICULARS OF THESE RIGHTS OR CONSULT WITH A LEGAL ADVISOR.

PURSUANT TO SECTION 3A.3 OF NATIONAL INSTRUMENT 33-105 UNDERWRITING CONFLICTS (NI 33-105), THE UNDERWRITERS ARE NOT REQUIRED TO COMPLY WITH THE DISCLOSURE REQUIREMENTS OF NI 33-105 REGARDING UNDERWRITER CONFLICTS OF INTEREST IN CONNECTION WITH THIS OFFERING.

NOTICE TO PROSPECTIVE INVESTORS IN THE EUROPEAN ECONOMIC AREA ("EEA")

PROHIBITION ON SALES TO EU RETAIL INVESTORS

THE BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND WILL NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY EU RETAIL INVESTOR IN THE EUROPEAN ECONOMIC AREA ("EEA"). FOR PURPOSES OF THIS PROVISION:

(A) THE EXPRESSION "EU RETAIL INVESTOR" MEANS A PERSON WHO IS ONE (OR MORE) OF THE FOLLOWING:

(I) A RETAIL CLIENT AS DEFINED IN POINT (11) OF ARTICLE 4(1) OF DIRECTIVE 2014/65/EU (AS AMENDED, "MIFID II"); OR

(II) A CUSTOMER WITHIN THE MEANING OF DIRECTIVE (EU) 2016/97, AS AMENDED, WHERE THAT CUSTOMER WOULD NOT QUALIFY AS A PROFESSIONAL CLIENT AS DEFINED IN POINT (10) OF ARTICLE 4(1) OF MIFID II; OR

(III) NOT A QUALIFIED INVESTOR ("EU QUALIFIED INVESTOR") AS DEFINED IN ARTICLE 2 OF REGULATION (EU) 2017/1129 (AS AMENDED, THE "EU PROSPECTUS REGULATION"); AND

(B) THE EXPRESSION "OFFER" INCLUDES THE COMMUNICATION IN ANY FORM AND BY ANY MEANS OF SUFFICIENT INFORMATION ON THE TERMS OF THE OFFER AND THE BONDS TO BE OFFERED SO AS TO ENABLE AN INVESTOR TO DECIDE TO PURCHASE OR SUBSCRIBE FOR THE BONDS.

CONSEQUENTLY, NO KEY INFORMATION DOCUMENT REQUIRED BY REGULATION (EU) NO 1286/2014 (AS AMENDED, THE "EU PRIIPS REGULATION") FOR OFFERING OR SELLING THE BONDS OR OTHERWISE MAKING THEM AVAILABLE TO EU RETAIL INVESTORS IN THE EEA HAS BEEN PREPARED AND THEREFORE OFFERING OR SELLING THE BONDS OR OTHERWISE MAKING THEM AVAILABLE TO ANY EU RETAIL INVESTOR IN THE EEA MAY BE UNLAWFUL UNDER THE EU PRIIPS REGULATION.

OTHER EEA OFFERING RESTRICTIONS

THIS OFFICIAL STATEMENT IS NOT A PROSPECTUS FOR THE PURPOSES OF THE EU PROSPECTUS REGULATION. THIS OFFICIAL STATEMENT HAS BEEN PREPARED ON THE BASIS THAT ANY OFFER OF BONDS IN THE EEA WILL ONLY BE MADE TO EU QUALIFIED INVESTORS. ACCORDINGLY ANY PERSON MAKING OR INTENDING TO MAKE AN OFFER IN THE EEA OF BONDS MAY ONLY DO SO WITH RESPECT TO EU QUALIFIED INVESTORS. NONE OF THE ISSUER OR ANY OF THE UNDERWRITERS HAVE AUTHORIZED, NOR DO THEY AUTHORIZE, THE MAKING OF ANY OFFER OF BONDS IN THE EEA OTHER THAN TO EU QUALIFIED INVESTORS.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED KINGDOM

PROHIBITION ON SALES TO UK RETAIL INVESTORS

THE BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND WILL NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY UK RETAIL INVESTOR IN THE UNITED KINGDOM ("UK"). FOR PURPOSES OF THIS PROVISION:

(A) THE EXPRESSION "UK RETAIL INVESTOR" MEANS A PERSON WHO IS ONE (OR MORE) OF THE FOLLOWING:

(i) A RETAIL CLIENT AS DEFINED IN POINT (8) OF ARTICLE 2 OF COMMISSION DELEGATED REGULATION (EU) 2017/565, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUROPEAN UNION (WITHDRAWAL) ACT 2018 (AS AMENDED, THE "EUWA") AND AS AMENDED; OR

(ii) A CUSTOMER WITHIN THE MEANING OF THE PROVISIONS OF THE UK FINANCIAL SERVICES AND MARKETS ACT 2000 (AS AMENDED, "FSMA") AND ANY RULES OR REGULATIONS MADE UNDER FSMA (SUCH RULES AND REGULATIONS AS AMENDED) TO IMPLEMENT DIRECTIVE (EU) 2016/97, WHERE THAT CUSTOMER WOULD NOT QUALIFY AS A PROFESSIONAL CLIENT, AS DEFINED IN POINT (8) OF ARTICLE 2(1) OF REGULATION (EU) NO 600/2014, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED ("UK MIFIR"); OR

(iii) NOT A QUALIFIED INVESTOR ("UK QUALIFIED INVESTOR") AS DEFINED IN ARTICLE 2 OF REGULATION (EU) 2017/1129, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED (THE "UK PROSPECTUS REGULATION"); AND

(B) THE EXPRESSION "OFFER" INCLUDES THE COMMUNICATION IN ANY FORM AND BY ANY MEANS OF SUFFICIENT INFORMATION ON THE TERMS OF THE OFFER AND THE BONDS TO BE OFFERED SO AS TO ENABLE AN INVESTOR TO DECIDE TO PURCHASE OR SUBSCRIBE FOR THE BONDS.

CONSEQUENTLY, NO KEY INFORMATION DOCUMENT REQUIRED BY REGULATION (EU) NO 1286/2014 (AS AMENDED), AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED (THE "UK PRIIPS REGULATION") FOR OFFERING OR SELLING THE BONDS OR OTHERWISE MAKING THEM AVAILABLE TO UK RETAIL INVESTORS IN THE UK HAS BEEN PREPARED AND THEREFORE OFFERING OR SELLING THE BONDS OR OTHERWISE MAKING THEM AVAILABLE TO ANY UK RETAIL INVESTOR IN THE UK MAY BE UNLAWFUL UNDER THE UK PRIIPS REGULATION.

OTHER UK OFFERING RESTRICTIONS

THIS OFFICIAL STATEMENT IS NOT A PROSPECTUS FOR THE PURPOSES OF THE UK PROSPECTUS REGULATION. THIS OFFICIAL STATEMENT HAS BEEN PREPARED ON THE BASIS THAT ANY OFFER OF BONDS IN THE UK WILL ONLY BE MADE TO UK QUALIFIED INVESTORS. ACCORDINGLY ANY PERSON MAKING OR INTENDING TO MAKE AN OFFER IN THE UK OF BONDS MAY ONLY DO SO WITH RESPECT TO UK QUALIFIED INVESTORS. NONE OF THE ISSUER OR ANY OF THE UNDERWRITERS HAVE AUTHORIZED, NOR DO THEY AUTHORIZE, THE MAKING OF ANY OFFER OF BONDS IN THE UK OTHER THAN TO UK QUALIFIED INVESTORS.

OTHER UK REGULATORY RESTRICTIONS

IN THE UK, THIS OFFICIAL STATEMENT IS BEING COMMUNICATED ONLY TO AND IS BEING DIRECTED ONLY AT, PERSONS WHO (1) HAVE PROFESSIONAL EXPERIENCE IN MATTERS RELATING TO INVESTMENTS AND WHO FALL WITHIN ARTICLE 19(5) OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 (FINANCIAL PROMOTION) ORDER 2005 (AS AMENDED, THE "FINANCIAL PROMOTION ORDER"), (2) ARE PERSONS FALLING WITHIN ARTICLE 49(2)(a) TO (d) ("HIGH NET WORTH COMPANIES, UNINCORPORATED ASSOCIATIONS ETC.") OF THE FINANCIAL PROMOTION ORDER OR (3) ARE PERSONS TO WHOM IT MAY OTHERWISE LAWFULLY BE COMMUNICATED UNDER SECTION 21 OF FSMA (ALL SUCH PERSONS TOGETHER BEING REFERRED TO AS "RELEVANT PERSONS"). IN THE UK, THIS OFFICIAL STATEMENT MUST NOT BE ACTED ON OR RELIED ON BY PERSONS WHO ARE NOT RELEVANT PERSONS. IN THE UK, ANY INVESTMENT OR INVESTMENT ACTIVITY TO WHICH THIS OFFICIAL STATEMENT RELATES, INCLUDING THE BONDS, IS AVAILABLE ONLY TO RELEVANT PERSONS AND WILL BE ENGAGED IN ONLY WITH RELEVANT PERSONS.

NO PERSON MAY COMMUNICATE OR CAUSE TO BE COMMUNICATED ANY INVITATION OR INDUCEMENT TO ENGAGE IN INVESTMENT ACTIVITY (WITHIN THE MEANING OF SECTION 21 OF

FSMA) RECEIVED BY IT IN CONNECTION WITH THE ISSUE OR SALE OF THE BONDS OTHER THAN IN CIRCUMSTANCES IN WHICH SECTION 21(1) OF FSMA DOES NOT APPLY.

POTENTIAL INVESTORS IN THE UK ARE ADVISED THAT ALL, OR MOST, OF THE PROTECTIONS AFFORDED BY THE UK REGULATORY SYSTEM WILL NOT APPLY TO AN INVESTMENT IN THE BONDS AND THAT COMPENSATION WILL NOT BE AVAILABLE UNDER THE UK FINANCIAL SERVICES COMPENSATION SCHEME.

NOTICE TO PROSPECTIVE INVESTORS IN SWITZERLAND

PROHIBITION OF SALES TO SWISS RETAIL INVESTORS

THE BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND SHOULD NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY RETAIL INVESTOR IN SWITZERLAND. FOR THESE PURPOSES, A RETAIL INVESTOR MEANS A PERSON WHO IS A RETAIL CLIENT AS DEFINED IN ARTICLE 4 OF THE SWISS FINANCIAL SERVICES ACT (“FINSA”).

NO KEY INFORMATION DOCUMENT ACCORDING TO FINSA OR ANY EQUIVALENT DOCUMENT UNDER FINSA HAS BEEN PREPARED IN RELATION TO THE BONDS, AND, THEREFORE, THE BONDS MAY NOT BE OFFERED OR RECOMMENDED TO RETAIL CLIENTS WITHIN THE MEANING OF FINSA IN SWITZERLAND.

EXEMPTION TO PREPARE A FINSA-COMPLIANT PROSPECTUS

THE OFFERING OF THE BONDS IN SWITZERLAND IS EXEMPT FROM THE REQUIREMENT TO PREPARE AND PUBLISH A PROSPECTUS UNDER FINSA BECAUSE SUCH OFFERING IS MADE TO PROFESSIONAL CLIENTS AND INSTITUTIONAL CLIENTS WITHIN THE MEANING OF FINSA ONLY. THIS DOCUMENT DOES NOT CONSTITUTE A PROSPECTUS PURSUANT TO FINSA, AND NO SUCH PROSPECTUS HAS BEEN OR WILL BE PREPARED FOR OR IN CONNECTION WITH THE OFFERING OF THE BONDS.

NOTICE TO PROSPECTIVE INVESTORS IN JAPAN

THE BONDS HAVE NOT BEEN AND WILL NOT BE REGISTERED PURSUANT TO ARTICLE 4, PARAGRAPH 1 OF THE FINANCIAL INSTRUMENTS AND EXCHANGE ACT OF JAPAN (LAW NO. 25 OF 1948, AS AMENDED (“FIEA”)) AND, ACCORDINGLY, NEITHER THE BONDS NOR ANY INTEREST IN THEM MAY BE OFFERED OR SOLD, DIRECTLY OR INDIRECTLY, IN JAPAN OR TO, OR FOR THE BENEFIT, OF ANY RESIDENT OF JAPAN OR TO OTHERS FOR RE-OFFERING OR RESALE, DIRECTLY OR INDIRECTLY, IN JAPAN OR TO A RESIDENT OF JAPAN EXCEPT UNDER CIRCUMSTANCES WHICH WILL RESULT IN COMPLIANCE WITH ALL APPLICABLE LAWS, REGULATIONS AND GUIDELINES PROMULGATED BY THE RELEVANT JAPANESE GOVERNMENTAL AND REGULATORY AUTHORITIES AND IN EFFECT AT THE RELEVANT TIME. FOR THE PURPOSES OF THIS PARAGRAPH, “RESIDENT OF JAPAN” MEANS A NATURAL PERSON HAVING HIS/HER PLACE OF DOMICILE OR RESIDENCE IN JAPAN, OR A LEGAL PERSON HAVING ITS MAIN OFFICE IN JAPAN. A BRANCH, AGENCY OR OTHER OFFICE IN JAPAN OF A NON-RESIDENT, IRRESPECTIVE OF WHETHER IT IS LEGALLY AUTHORIZED TO REPRESENT ITS PRINCIPAL OR NOT, SHALL BE DEEMED TO BE A RESIDENT OF JAPAN EVEN IF ITS MAIN OFFICE IS IN ANY COUNTRY OTHER THAN JAPAN. RESIDENT OF JAPAN SHALL EXCLUDE NON-RESIDENTS OF JAPAN, AS SUCH TERM IS DEFINED IN ARTICLE 6, PARAGRAPH 1, SUB-PARAGRAPH 6 OF THE FOREIGN EXCHANGE AND TRADE ACT OF JAPAN (ACT. NO. 228 OF 1949, AS AMENDED).

THE OFFERING OF THE BONDS IN JAPAN ARE BEING MADE BY MEANS OF A PRIVATE PLACEMENT TO QUALIFIED INSTITUTIONAL INVESTORS (TEKIKAKU-KIKAN-TOSHIKA) (WITHIN THE MEANING OF SUCH TERM PROVIDED FOR UNDER ARTICLE 2, PARAGRAPH 3, SUB-PARAGRAPH 1 OF THE FIEA AND ARTICLE 10, PARAGRAPH 1 OF THE CABINET OFFICE ORDINANCE CONCERNING

DEFINITIONS PROVIDED IN ARTICLE 2 OF THE FINANCIAL INSTRUMENTS AND EXCHANGE ACT IN JAPAN (MINISTRY OF FINANCE ORDINANCE NO.14 OF 1993, AS AMENDED)) ("QIIS"). THE OFFERING OF THE BONDS IN JAPAN SHALL BE MADE ON THE CONDITIONS THAT THE BONDS SHALL NOT BE TRANSFERRED TO ANY PERSON OTHER THAN QIIS AND A DOCUMENT INCLUDING THE INFORMATION ON THE BONDS AND TO BE DELIVERED TO A PROSPECTIVE PURCHASER SHALL STATE THAT THE BONDS SHALL NOT BE TRANSFERRED TO ANY PERSON OTHER THAN A QIIS.

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TABLE CONTENTS

Page

OFFICIAL STATEMENT

$76,020,000
Port of Morrow, Oregon
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 9),
Series 2024 (Federally Taxable) (Green Bonds – Climate Bond Certified)

INTRODUCTORY STATEMENT

This Official Statement provides information concerning the issuance by the Port of Morrow, Oregon (the "Issuer" or the "Port") of $76,020,000 principal amount of its Transmission Facilities Revenue Bonds, Series 2024 (the "Series 2024 Bonds"). The Series 2024 Bonds are being issued for the purpose of financing the costs of acquisition of certain transmission facilities (the "Project"), as further described herein under "THE PROJECT," to be owned by the Issuer and leased to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville").

The Issuer will execute a Lease-Purchase Agreement with Bonneville dated June 13, 2024 (the "Lease-Purchase Agreement") pursuant to which the Issuer will lease the Project to Bonneville. The Series 2024 Bonds will be issued under an Indenture of Trust dated as of June 1, 2024 (the "Indenture") between the Issuer and U.S. Bank Trust Company, National Association, as trustee (the "Trustee"). Under the Indenture, the Issuer will assign to the Trustee certain rights under the Lease-Purchase Agreement, including the right to receive rental payments from Bonneville in amounts at least sufficient to pay when due the principal of, and interest on, the Series 2024 Bonds.

Brief descriptions and summaries of the Series 2024 Bonds, the Lease-Purchase Agreement and the Indenture follow in this Official Statement. These descriptions and summaries do not purport to be complete and are subject to and qualified by reference to the provisions of the complete documents, copies of which are available at the offices of the Trustee at Global Corporate Trust Services, 170 S Main Street, Suite 200, Salt Lake City, UT 84101. Appendices A and B to this Official Statement have been furnished by Bonneville and contain information concerning the business of Bonneville. Capitalized terms not otherwise defined herein shall have the meanings given to such terms in the Indenture.

THE ISSUER

General

The Issuer, a port district located in Morrow County, Oregon, was organized in 1957 under Oregon Revised Statutes, Section 777, as amended. The Issuer's boundaries, approximately 2,049 square miles, are coterminous with Morrow County. To the north, the Issuer is bordered by the Columbia River and is transected by Interstate 84 and Union Pacific railroad mainline. Both the highway and the railroad pass through Boardman, the location of the Port's administrative office and a portion of its industrial park.

Port districts in the State of Oregon are authorized to acquire, hold, use, enjoy and convey, lease or otherwise dispose of real and personal property, or any interest therein, necessary or convenient in carrying out its powers. Port powers include the right to acquire rights of way for the placing of transmission lines over which to carry electric energy, with the full power to lease and sell the same, together with the lands upon which they are situated, whether held by the port in its governmental capacity or not.

The Port's major mission remains economic development and creation of jobs for the cities of Boardman, Lexington, Heppner, Ione and Irrigon. The Port's area has approximately 12,300 residents. A five member Board of Commissioners governs the Port.

Board of Commissioners

Name	Title	Occupation	Current Term Began	Term Ends
Joe Taylor	President	Farmer	07/01/21	06/30/25
John Murray	Vice President	Pharmacist	07/01/23	06/30/27
Rick Stokoe	Secretary/Treasurer	Police Chief	07/01/21	06/30/25
Kelly Doherty	Commissioner	Rancher	07/01/23	06/30/27
Joel Peterson	Commissioner	Farmer	10/23/23	06/30/25

Administration

The Port employs an executive director, who is responsible for all management and administrative functions. The executive director has a staff of 146 full-time equivalent employees to assist in administrative and facility maintenance activities.

Limited Obligation

The Series 2024 Bonds shall not be payable out of any funds of the Issuer other than those pledged therefor but shall be payable by the Issuer solely from the Trust Estate. Nothing in the Series 2024 Bonds, in the Lease-Purchase Agreement or in the Indenture or any other agreement or binding document shall be considered as pledging any other funds or assets of the Issuer. All right, title, and interest of the Issuer in and to the Trust Estate shall be pledged to the Trustee for the benefit of Series 2024 Bondholders for the payment of the principal of, premium, if any, and interest on the Series 2024 Bonds in accordance with their terms and provisions of the Indenture. THE SERIES 2024 BONDS, TOGETHER WITH THE INTEREST THEREON, SHALL BE SPECIAL LIMITED OBLIGATIONS OF THE ISSUER PAYABLE SOLELY FROM THE TRUST ESTATE PLEDGED UNDER THE INDENTURE; AND THE SERIES 2024 BONDS SHALL NOT CONSTITUTE A DEBT OR PLEDGE OF THE FULL FAITH AND CREDIT OR TAXING POWER OF THE STATE, THE ISSUER OR ANY POLITICAL SUBDIVISION OF THE STATE OR A LOAN OF THE CREDIT OF ANY OF THE FOREGOING WITHIN THE MEANING OF ANY CONSTITUTIONAL OR STATUTORY LIMITATION AND SHALL NEVER CONSTITUTE OR GIVE RISE TO A PECUNIARY LIABILITY OF THE STATE, THE ISSUER OR ANY POLITICAL SUBDIVISION OF THE STATE. NO OWNER OF ANY SERIES 2024 BONDS SHALL HAVE THE RIGHT TO COMPEL ANY EXERCISE OF TAXING POWER OF THE STATE, THE ISSUER OR ANY POLITICAL SUBDIVISION OF THE STATE, INCLUDING THE ISSUER, TO PAY THE SERIES 2024 BONDS OR THE INTEREST THEREON. THE LEASE-PURCHASE AGREEMENT SHALL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR A CHARGE AGAINST THE GENERAL CREDIT OR TAXING POWER OF THE STATE, THE ISSUER OR ANY POLITICAL SUBDIVISION OF THE STATE WITHIN THE MEANING OF ANY CONSTITUTIONAL OR STATUTORY LIMITATION.

VALIDATION

On March 15, 2012, the Circuit Court of the State of Oregon of the County of Morrow, in a validation procedure brought by the Issuer, determined among other things, that the Issuer has the authority to issue revenue bonds in one or more series and to enter into financing agreements to finance or refinance the costs of acquisition, installation and/or construction of future or existing transmission facilities which are now or will be leased to Bonneville and that upon execution and delivery thereof, all bonds issued in connection with said transmission facilities, including the Series 2024 Bonds, and any leases or indentures executed in connection with such transmission facilities, including the Indenture and Lease-Purchase Agreement, will be valid, legal and binding obligations in accordance with their terms.

The judgment binds and permanently enjoins all persons from the institution of any action or proceeding challenging the validity of any bonds, indentures or leases in connection with such transmission facilities or any matters adjudicated in such validation actions or which could have adjudicated in such actions. The validation judgment became effective on April 15, 2012.

PURPOSE OF ISSUANCE AND USE OF PROCEEDS

Pursuant to a lease-purchase agreement and a related construction agreement dated as of March 15, 2018, between Bonneville and the Idaho Energy Resources Authority ("IERA"), IERA provided for the acquisition, construction, installation and equipping of certain transmission facilities (as described below, the "Project") and leased the Project to Bonneville. IERA financed such acquisition, construction, installation and equipping through a note purchase agreement with Wells Fargo Bank, National Association, and secured its obligations under such note purchase agreement with the lease-purchase agreement by and between IERA, as lessor, and Bonneville, as lessee, and the payments from Bonneville thereunder.

The proceeds from the sale of the Series 2024 Bonds will be used by the Issuer to acquire the Project from IERA. IERA will use the funds received from the Issuer to pay the indebtedness incurred under said note purchase agreement. Upon receipt of the acquisition payment, IERA will relinquish all of its rights and interests in the Project and irrevocably transfer such rights and interests to the Issuer. The proceeds from the sale of the Series 2024 Bonds will also be used by the Issuer to pay the costs of issuance of the Series 2024 Bonds (including Underwriters' discount and fees and disbursements of Underwriters' counsel) and certain administrative costs of the Issuer. The costs of issuance and such administrative costs are $656,590.63.

DESIGNATION OF SERIES 2024 BONDS AS GREEN BONDS – CLIMATE BOND CERTIFIED

The information set forth below concerning (i) the Climate Bonds Initiative and the process for obtaining certification from the Climate Bonds Standard Board on behalf of the Climate Bonds Initiative, and (2) Kestrel in its role as a verifier with respect to the certification of the Series 2024 Bonds as Climate Bond Certified, all as more fully described below, has been extracted from materials provided by the Climate Bonds Initiative and Kestrel. Additional information can be found at www.climatebonds.net. The Climate Bonds Initiative website is included for reference only and the information contained therein is not incorporated by reference in this Official Statement.

In connection with the Series 2024 Bonds and the Project, the Issuer and Bonneville applied to the Climate Bonds Initiative for designation of the Series 2024 Bonds as "Climate Bond Certified." The Climate Bonds Initiative is an independent not-for-profit organization that works solely on mobilizing the bond market for climate change solutions. The Climate Bonds Initiative has established a certification program that provides criteria for eligible projects to be considered a Certified Climate Bond. Rigorous scientific criteria ensure that financed activities are consistent with the 1.5 degrees Celsius warming target declared in the 2015 Paris Agreement which exists within the United Nations Framework Convention on Climate Change, to address greenhouse-gas-emissions mitigation, adaptation, and finance. The Climate Bonds Initiative certification program is used globally by bond issuers, governments, investors and the financial markets to prioritize investments which genuinely contribute to addressing climate change.

The Climate Bonds Standard and Sector Criteria include credible, science-based, widely supported guidelines about what should and should not be considered a qualifying climate-aligned investment to assist investors in making informed decisions about the environmental credentials of a bond. In order to receive the Climate Bonds certification, the Issuer and Bonneville engaged Kestrel, a third-party Climate Bonds Initiative Approved Verifier, to provide verification to the Climate Bonds Standard Board that the Series 2024 Bonds meet the Climate Bonds Standard and relevant Sector Criteria. Kestrel reviewed and provided verification to the Climate Bonds Initiative, and the Climate Bonds Standard Board certified the Series 2024 Bonds as Climate Bonds on May 16, 2024. Kestrel will also provide a Post-Issuance Report to the Climate Bonds Initiative as to whether the proceeds of the Series 2024 Bonds have been allocated properly.

Per the International Capital Market Association (the "ICMA"), Green Bonds are any type of bond instrument where the proceeds will be exclusively applied to finance or re-finance, in part or in full, new and/or existing eligible Green Projects and which are aligned with the four core components of the Green Bond Principles. The four core components are: 1. Use of Proceeds; 2. Process for Project Evaluation and Selection; 3. Management of Proceeds; and 4. Reporting.

Kestrel has also determined that the Series 2024 Bonds are in conformance with the four core components of the ICMA Green Bond Principles.

The terms "Climate Bond Certified" and "Green Bonds" are solely for identification purposes and are not intended to provide or imply that the owners of the Series 2024 Bonds are entitled to any security other than that described under the heading "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS."

The certification of the Series 2024 Bonds as Climate Bonds by the Climate Bonds Initiative is based solely on the Climate Bonds Standard and does not, and is not intended to, make any representation, warranty, undertaking, express or implied, or give any assurance with respect to any other matter relating to the Series 2024 Bonds or the Project, including but not limited to the Official Statement, the transaction documents, the Issuer or the management of the Issuer.

The certification of the Series 2024 Bonds as Climate Bonds by the Climate Bonds Initiative was addressed solely to the Issuer and Bonneville and is not a recommendation to any person to purchase, hold or sell the Series 2024 Bonds and such certification does not address the market price or suitability of the Series 2024 Bonds for a particular investor. Each potential purchaser of the Series 2024 Bonds should determine for itself the relevance of this certification. Any purchase of Series 2024 Bonds should be based upon such investigation that each potential purchaser deems necessary. The certification also does not address the merits of the decision by the Issuer or any third party to participate in any nominated project and does not express and should not be deemed to be an expression of an opinion as to the Issuer or any aspect of the Project (including but not limited to the financial viability of the Project) other than with respect to conformance with the Climate Bonds Standard.

In issuing or monitoring, as applicable, the certification, the Climate Bonds Initiative and Kestrel have assumed and relied upon and will assume and rely upon the accuracy and completeness in all material respects of the information supplied or otherwise made available to the Climate Bonds Initiative and Kestrel. The Climate Bonds Initiative does not assume or accept any responsibility or liability to any person for independently verifying (and it has not verified) such information or to undertake (and it has not undertaken) any independent evaluation of any nominated project or the Issuer or Bonneville.

In addition, the Climate Bonds Initiative does not assume any obligation to conduct (and it has not conducted) any physical inspection of any nominated project. The certification may only be used with the Series 2024 Bonds and may not be used for any other purpose without the Climate Bonds Initiative's prior written consent.

The certification does not and is not in any way intended to address the likelihood of timely payment of interest when due on the Series 2024 Bonds and/or the payment of principal at maturity or any other date.

The certification may be withdrawn at any time in the Climate Bonds Initiative's sole and absolute discretion and there can be no assurance that such certification will not be withdrawn.

Approved Verifier for Third Party Verification of Climate Bond

The Issuer and Bonneville have engaged Kestrel to provide a Verification on the Series 2024 Bonds' conformance with the Climate Bonds Standard V4.0. Kestrel has determined that the projects and activities to be financed with the proceeds of the Series 2024 Bonds satisfy the Climate Bonds Standard V4.0 and Electric Grids and Storage Criteria, and the ICMA Green Bond Principles. Accredited as an "Approved Verifier" by the Climate Bonds Initiative, Kestrel evaluates bonds against the Climate Bonds Standard and Sector Criteria in all sectors worldwide. Kestrel's Climate Bond Verifier's Report can be found in Appendix F.

THE PROJECT

The Issuer holds title to the Project which is leased to the United States Department of Energy, acting by and through the Administrator of the Bonneville Power Administration. The Project consists solely of fixtures and/or equipment that are a part of electric transmission system facilities located in the Pacific Northwest region of the United States. The Project includes: (i) additions or replacements at four Federal Columbia River Power System (the "Federal System") substations for aluminum bus, cable, shunt reactors, shunt capacitors, current limiting reactors, grounding system, fencing, gates, insulators, metering systems, oil spill containment systems, power circuit breakers, power transformers, series capacitor banks, harmonic filters, static var compensator ("SVC") thyristor valves, SVC valve cooling equipment, SVC control, protection, and alarm monitoring systems, surge arresters, switchyard surface crushed rock, security enhancements, sequential events recorder system, supervisory control and data acquisition system, station service cabinets and transformers, switchboard panels, wood poles, and necessary hardware; and (ii) additions at one Federal System equipment and storage facility including pre-engineered metal buildings with foundations, interior steel framing and insulated metal exterior wall panel system with standing seam metal roof, heating, ventilation, air conditioning, vehicle exhaust system and fire detection/prevention systems, electric and lighting systems, overhead travel cranes affixed to the building structure, fencing, gates, and necessary hardware.

Bonneville's leasehold interests in the Project and its rights and obligations in connection therewith are a part of the "Federal Transmission System" as described in Bonneville's organic statutes. Bonneville has obtained and holds, in the name of the United States of America, all of the rights of way and other real property interests associated with the land on which the Project is sited. These real property interests are not subject to condemnation by any state or local authority.

Under the Lease-Purchase Agreement and the Indenture, the definition of the Project may be amended from time to time without the consent of the holders of the Series 2024 Bonds; provided, however, that a change in the definition of the Project shall not entitle Bonneville to any abatement or reduction in the rental payments under the Lease-Purchase Agreement. See "THE LEASE-PURCHASE AGREEMENT - Changing the Definition of the Project."

The Series 2024 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described under "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS – Trust Estate." Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2024 Bonds. See "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS."

SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS

Trust Estate

Under the terms of the Indenture, the Series 2024 Bonds are payable solely but equally and ratably from and are secured solely but equally and ratably by the Trust Estate which consists of (i) all right, title and interest of the Issuer in and to the Lease-Purchase Agreement, including all rental payments, revenues and receipts payable or receivable thereunder, excluding, however, the Issuer's Reserved Rights, which rights may be enforced by the Issuer and the Trustee jointly or severally; (ii) all right, title and interest of the Issuer in and to the Project, subject to the Lease-Purchase Agreement; (iii) all moneys and securities from time to time held by the Trustee under the terms of the Indenture including amounts set apart and transferred to the Project Fund, the Bond Fund or the Reserve Fund, and all investment earnings of any of the foregoing, subject to disbursements from the Project Fund, the Bond Fund, or the Reserve Fund in accordance with the provisions of the Lease-Purchase Agreement and the Indenture; (iv) any and all other property of every kind and nature from time to time which was heretofore or will be hereafter by delivery or by writing of any kind conveyed, mortgaged, pledged, assigned or transferred, as and for additional security under the Indenture, by the Issuer or by any other person, firm or corporation with or without the consent of the Issuer, to the Trustee which is hereby authorized to receive any and all such property at any time and at all times to hold and apply the same subject to the terms of the Indenture.

Pursuant to the Lease-Purchase Agreement between Bonneville and the Issuer, Bonneville is required to make rental payments in the amounts set forth in schedules contained in the Lease-Purchase Agreement which schedules will provide for rental payments at times and in amounts more than sufficient to pay the principal of and interest and all other amounts due on the Series 2024 Bonds. See herein "THE LEASE-PURCHASE AGREEMENT" and "THE INDENTURE." Such rental payments are irrevocably pledged by the Issuer pursuant to the Indenture for the payment of principal or redemption premium, if any, of and interest on the Series 2024 Bonds. The Lease-Purchase Agreement provides that such rental payments will be made directly to the Trustee for deposit in the Bond Fund.

The Lease-Purchase Agreement provides that Bonneville's obligation to pay the rental payments and all other amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project is operating or operable. Bonneville's obligation to make the rental payments will continue until September 1, 2032, unless sooner terminated or extended in accordance with the provisions of the Lease-Purchase Agreement, and is coterminous with the final maturity of the Series 2024 Bonds. **Bonneville's obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.**

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease-Purchase Agreement. The Issuer and Bonneville will declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer will waive any rights it may have as a secured party with respect to the Project. The Series 2024 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described above. Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2024 Bonds. See "THE PROJECT."

Source of Bonneville's Payments: The Bonneville Fund

The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see APPENDIX A – "BONNEVILLE POWER ADMINISTRATION—Bonneville Financial Operations—The Bonneville Fund."

Bonneville may make expenditures from the Bonneville Fund, which shall have been included in Bonneville's annual budget submitted to Congress without further appropriation and without fiscal year limitation but subject to such specific directives or limitations as may be included in appropriations acts, for any purpose necessary or appropriate to carry out the duties imposed upon Bonneville pursuant to law.

Payments by Bonneville under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations or the Series 2024 Bonds intended to be or are they secured by the full faith and credit of the United States of America.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are to be made from net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System, other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the United States Corps of Engineers and the United States Bureau of Reclamation for certain costs allocated to electric power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville has made all payments to the United States Treasury in full and on time since 1984, including in Bonneville Fiscal Year 2023.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville for operating and maintenance expenses, including Bonneville's payments under the Lease-Purchase Agreement, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including payments relating to the Lease-Purchase Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its scheduled payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has not deferred such payments since 1983.

Bonneville also has a substantial number of agreements with Preference Customers, as hereinafter described in Appendix A - "BONNEVILLE POWER ADMINISTRATION—GENERAL," pursuant to which Bonneville has an obligation to provide credits against power and transmission purchases made from Bonneville by such customers. Under these "net billing" agreements, related Bonneville Preference Customers ("Participants") have the obligation to make payments to two third-parties (Energy Northwest and the City of Eugene, Oregon, Water and Electric Board ("EWEB")) to meet the costs of certain nuclear generating projects, one of which is currently operating. In return, Bonneville has an obligation to the Participants to provide payment credits ("net billing credits") against the monthly power and transmission bills issued by Bonneville. The net billing credits reduce the amount of cash that Bonneville would otherwise have to pay its cash payment obligations. The occurrence of net billing credits is determined in part by the availability of funds to Energy Northwest and EWEB, apart from net billing, to cover the related projects' costs. As described below, Bonneville has entered into certain direct payment agreements that result in direct payments from Bonneville to Energy Northwest and EWEB for all related project costs. These agreements have enabled Energy Northwest and EWEB to reduce net billing to zero. However, if Bonneville is unable or fails to make direct payments, or if certain other conditions occur, net billing would be re-established. For additional descriptions of Bonneville's substantial net billing arrangements, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—POWER SERVICES—Description of the Generation Resources of the Federal System," "—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects," and "—BONNEVILLE FINANCIAL OPERATIONS—Direct Pay Agreements." Bonneville has other crediting commitments that are similar to net billing credits in that they reduce the amount of revenue in cash that Bonneville receives. See APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments" and "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) net billed project costs to the extent covered by net billing credits, (2) cash payments out of the Bonneville Fund to cover all required payments incurred by Bonneville pursuant to law, including but not limited to lease rental payments by Bonneville under the Lease-Purchase Agreement and other operating and maintenance expenses, including net billing cash payments and payments under the direct payment agreements and the costs of electric power conservation or generating resource acquisitions, but excluding payments to the United States Treasury and (3) payments to the United States Treasury. For further information, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE Financial Operations—Order in Which Bonneville's Costs Are Met."

Bonneville has substantial outstanding repayment obligations to the United States Treasury ("Federal Debt") and for debt issued by third parties (and similar obligations), the repayment of which is secured by Bonneville financial commitments ("Non-Federal Debt"). Non-Federal Debt includes lease-purchase agreements, net billing agreements, and other obligations. As of September 30, 2023, aggregate debt outstanding was approximately $14.8 billion, half of which relates to outstanding Non-Federal Debt. For further information on Non-Federal Debt, see APPENDIX A — "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt."

THE SERIES 2024 BONDS

General

The Series 2024 Bonds will be issued originally as a single global certificate for each maturity registered to DTC, or its nominee, Cede & Co., to be held in DTC's book-entry-only system. So long as the Series 2024 Bonds are held in the book-entry-only system, DTC (or a successor securities depository) or its nominee will be the registered owner of the Series 2024 Bonds for all purposes of the Indenture, the Series 2024 Bonds and this Official Statement. Interest on the Series 2024 Bonds will be payable only through participants or indirect participants in DTC so long as the Series 2024 Bonds are held in the book-entry-only system. The Series 2024 Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. See "Book-Entry-Only System" below.

The Series 2024 Bonds are dated the date of their delivery, and mature on September 1 in the years and in the principal amounts shown on the cover page of this Official Statement. The Series 2024 Bonds will bear interest, computed on the basis of a 360-day year of twelve 30-day months, at the rates shown on the cover page of this Official Statement. The Series 2024 Bonds are subject to redemption prior to maturity as set forth below. Additional Bonds may be issued under the Indenture. Such Bonds, together with the Series 2024 Bonds, are referred to as the "Bonds."

Interest on the Series 2024 Bonds will be payable on March 1 and September 1 of each year, commencing September 1, 2024, to the persons in whose name the Series 2024 Bonds are registered on the fifteenth day of the month preceding the interest payment date; provided that overdue interest shall be paid to the persons in whose name such Series 2024 Bonds are registered by close of business on the fifth Business Day next preceding the date of payment of the defaulted interest. So long as the Series 2024 Bonds are held in the book-entry-only system, all payments of principal of and premium, if any, and interest are required to be made by the Trustee to DTC in immediately available funds for further distribution to beneficial owners of the Series 2024 Bonds.

Book-Entry-Only System

DTC will act as securities depository for the Series 2024 Bonds. The Series 2024 Bonds will be issued as fully-registered Series 2024 Bonds 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 Series 2024 Bond will be issued for the Series 2024 Bonds for each maturity, in the aggregate principal amount of such maturity, and will be deposited with DTC. See APPENDIX E — "DTC BOOK-ENTRY SYSTEM AND GLOBAL CLEARANCE PROCEDURE." Beneficial interests in the Series 2024 Bonds may be held through DTC, Clearstream Banking, S.A ("Clearstream Banking") or Euroclear Bank S.A./N.V. ("Euroclear") as operator of the Euroclear System, directly as a participant or indirectly through organizations that are participants in such system. For information on minimum unit sales for purchasers outside the United States, see "INFORMATION CONCERNING OFFERING RESTRICTIONS IN CERTAIN JURISDICTIONS OUTSIDE THE UNITED STATES."

Optional Redemption

The Series 2024 Bonds are subject to redemption prior to their respective maturities at the option of the Issuer (with the approval of Bonneville), in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The "Make-Whole Redemption Price" is the greater of (i) the issue price of the Series 2024 Bonds as shown on the cover page of this Official Statement (but not less than 100% of the principal amount of the Series 2024 Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2024 Bonds to be redeemed at the maturity date, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2024 Bonds are to be redeemed, discounted to the date on which such Series 2024 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 10 basis points, plus accrued and unpaid interest on the Series 2024 Bonds to be redeemed on the redemption date.

"Business Day" means a day (a) other than a day on which banks located in The City of New York, New York or the cities in which the principal corporate trust offices of the Trustee, the Paying Agent, the Lessee or the Issuer are located are required or authorized by law or executive order to close and (b) on which the New York Stock Exchange is not closed.

"Treasury Rate" means, with respect to any redemption date for a particular Series 2024 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 Price (defined below), as calculated by the Designated Investment Banker (defined below).

“Comparable Treasury Issue” means, with respect to any Valuation Date for a redemption date for a particular Series 2024 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 Series 2024 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 Series 2024 Bonds to be redeemed.

“Comparable Treasury Price” means, with respect to any Valuation Date for a redemption date for a particular Series 2024 Bond, (i) 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 (ii) if the yield described in (i) 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 Reference Treasury Dealer Quotations, the average of all such quotations.

“Designated Investment Banker” means one of the Reference Treasury Dealers appointed by the Issuer (with the approval of Bonneville).

“Reference Treasury Dealer” means each of five firms, specified by the Issuer (with the approval of Bonneville) 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 Issuer will substitute another Primary Treasury Dealer (with the approval of Bonneville).

“Reference Treasury Dealer Quotations” means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2024 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 Issuer, the Trustee and Bonneville 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 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.

Partial Redemption

If less than all of the Series 2024 Bonds are to be redeemed, the Issuer may select the maturity or maturities to be redeemed. The Indenture provides that the portion of any Series 2024 Bonds of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such Series 2024 Bonds for redemption, the Trustee will treat each such Series 2024 Bonds as representing that number of such Series 2024 Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2024 Bonds to be redeemed in part by $5,000.

The particular Series 2024 Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2024 Bonds are registered in book-entry-only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2024 Bonds, if less than all of a maturity of the Series 2024 Bonds of a maturity are called for redemption, the particular Series 2024 Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, or such other method as is in accordance with the operational arrangements of DTC then in effect. It is the Issuer’s intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between the Issuer and the Beneficial Owners be made in accordance with the pro rata pass-through distribution of principal basis described below. However, the Issuer can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among registered owners on such basis. If the DTC operational arrangements do not allow for the redemption of the Series 2024 Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2024 Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

If the Series 2024 Bonds are not registered in book-entry-only form, any redemption of less than all of a maturity of the Series 2024 Bonds shall be allocated among the registered owners of such Series 2024 Bonds as nearly as practicable in proportion to the principal amounts of the Series 2024 Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2024 Bonds. This will be calculated based on the following formula:

$$\frac{\text{(principal amount to be redeemed) x (principal amount owned by registered owner)}}{\text{(principal amount outstanding)}}$$

Notice of Redemption

Notice of redemption of any Series 2024 Bonds is to be given by the Trustee by first-class mail not less than 30 days nor more than 60 days before the redemption date to the registered owners of the Series 2024 Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2024 Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2024 Bonds which are to be redeemed, whether or not such notice is actually received. Failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the Series 2024 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2024 Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if money sufficient for the redemption of the Series 2024 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2024 Bonds on the redemption date and the Series 2024 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. The Issuer may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation, prior to the date scheduled for such redemption, to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry-only system is in effect with respect to the Series 2024 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2024 Bonds of a maturity are to be redeemed, DTC or its successor and Participants and Indirect Participants (as such terms are defined herein under the heading "THE SERIES 2024 BONDS – Book-Entry-Only System") will determine the particular ownership interests of Series 2024 Bonds to be redeemed. Any failure of DTC or its successor or a Participant or Indirect Participant to do so, or to notify a Beneficial Owner of a Series 2024 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2024 Bonds.

Neither the Issuer, the Trustee, nor the Underwriters can give any assurance that DTC, the Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2024 Bonds, or that they will do so on a timely basis.

THE LEASE-PURCHASE AGREEMENT

The following is a summary of certain provisions of the Lease-Purchase Agreement, to which reference is made for the detailed provisions thereof.

Rental Payments

Bonneville agrees under the Lease-Purchase Agreement to pay to the Trustee rental payments for deposit in the Bond Fund created under the Indenture in the amounts set forth in schedules to the Lease-Purchase Agreement, which schedules provide for rental payments more than sufficient for the payment of the principal of, and interest on, the Bonds. The obligation of Bonneville to make all payments provided in the Lease-Purchase Agreement is stated to be absolute and unconditional, without any set-off or counterclaim. See "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS" herein.

Bonneville has also agreed to pay, as additional rent under the Lease-Purchase Agreement, all Impositions, which are defined as all taxes and assessments, general and specific, if any, levied and assessed upon or against the Project, the Lease-Purchase Agreement, any estate or interest of the Issuer or Bonneville in the Project or transfer of such estate or interest, or the rental payments under the Lease-Purchase Agreement during the term of the Lease-

Purchase Agreement, and all assessments and other governmental charges and impositions whatsoever, foreseen or unforeseen, ordinary or extraordinary, under any present or future law, and charges for public or private utilities or other charges incurred in the occupancy, use, operation, maintenance or upkeep of the Project.

Indemnity

Bonneville agrees to pay all reasonable costs and expenses of the Issuer incurred in connection with the Lease-Purchase Agreement and to protect and indemnify the Issuer against and hold the Issuer harmless from (i) all costs and expenses arising from or relating to compliance with environmental laws and regulations and orders of governmental agencies applicable to the Project or arising from or relating to mitigation, remediation, or abatement of environmental impacts, (ii) any and all claims (whether in tort, contract or otherwise), demands, expenses (including reasonable attorneys' fees) and liabilities for any loss, damage, injury and liability of every kind and nature and however caused, including any liability arising from failure to comply with applicable environmental laws, regulations or orders applicable to the Project, and (iii) taxes of any kind and by whomsoever imposed on the Issuer in respect of the Project or the Bonds, in each case arising from or relating to the Project or resulting from, arising out of, or in any way connected with the financing of the costs of the Project and marketing, issuance or sale of the Bonds for such purpose (including amounts payable by the Issuer pursuant to its indemnification of the Trustee, the Bond Registrar and the Paying Agents); provided, however, that, Bonneville has no indemnification obligation for any such costs, expenses claims, demands, taxes or liabilities arising from the intentional misrepresentation or willful misconduct of the Issuer. Such indemnification set forth above shall be binding upon Bonneville for any and all claims, demands, expenses, liabilities and taxes set forth above and shall survive the expiration or termination of the Lease-Purchase Agreement. Any such payments shall be in addition to the above described rental payments under the Lease-Purchase Agreement.

Operation of the Project

The Issuer has no control over, and no obligation with respect to, the Project, including the operation, maintenance, repair, replacement or use of the Project. Bonneville will pay all costs of operating the Project and will make all decisions regarding the operation or use of the Project. Bonneville may, in its discretion, transfer operational control to a regional transmission organization or other entity; provided that Bonneville is required to remain liable under the Lease-Purchase Agreement. Bonneville may suspend, delay, or terminate operation of, take out of service, or dismantle the Project, or any portion thereof, in its discretion, provided that the Lease-Purchase Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the rental payments or other amounts payable by Bonneville under the Lease-Purchase Agreement. Bonneville will hold, in the name of the United States, all easements, rights of way, and any other interests in land under the Project and the Issuer shall have no rights therein.

Covenants

In the Lease-Purchase Agreement, Bonneville agrees, among other things, to pay all costs of maintaining the Project in the same manner in which Bonneville maintains similar facilities that it owns; to keep the Project free of liens, except as provided in the Lease-Purchase Agreement; to pay charges and assessments against the Project; to comply with law; to indemnify the Issuer and pay its fees and expenses as well as those of the Trustee; to furnish to the Trustee, any requesting holder of more than $1,000,000 of Series 2024 Bonds, and the Issuer, a copy of its financial statements, and to notify the Issuer and the Trustee of the occurrence of any Event of Default under the Lease-Purchase Agreement. See also "Continuing Disclosure" herein.

Damage, Destruction and Condemnation

If the Project is damaged, destroyed or condemned, there will be no reduction in the rental payments or other amounts payable under the Lease-Purchase Agreement. The Issuer shall have no obligation to rebuild, replace, repair or restore the Project. Bonneville will not be obligated to rebuild, replace, repair or restore the Project or any portion thereof or purchase the Project or any portion thereof following a loss event so long as the Lease-Purchase Agreement shall remain valid, binding and enforceable on Bonneville following such loss event. If Bonneville elects to rebuild, replace, repair or restore the Project or any portion thereof, it shall do so with its own or others' funds. Any proceeds of insurance or condemnation awards or recoveries of claims against contractors (or an amount equal to such proceeds, awards or recoveries) received by the Issuer or Bonneville shall be, as directed by Bonneville, deposited into the Project Fund or the Bond Fund for use to pay or reimburse the costs of repair or replacement of the related portions of the Project, for the prepayment of rental payments thereafter coming due, or as may otherwise be permitted in the Indenture; provided, however, that, if the foregoing proceeds (or amounts equal thereto) are received by Bonneville in respect of facilities that were a part of the Project when the damage or the basis for the claim originally arose but which facilities were subsequently removed from the definition of the Project, any proceeds (or amounts equal to such proceeds) received by Bonneville shall be retained by Bonneville as its own funds.

Termination of the Lease-Purchase Agreement

Upon the redemption or defeasance in whole of all outstanding Bonds in accordance with the Indenture, Bonneville may terminate the Lease-Purchase Agreement.

Defaults

The Lease-Purchase Agreement provides that any one or more of the following events will constitute an "Event of Default":

(a) Failure by Bonneville to pay when due any rental payment that has become due and payable under the Lease-Purchase Agreement; and

(b) Failure of Bonneville to pay any amount due under the Lease-Purchase Agreement (other than under paragraph (a) above) and continuance of such failure for thirty (30) days, after notice of such failure is given to Bonneville or the Issuer or the Trustee.

Remedies

Upon the occurrence and continuance of an Event of Default under the Lease-Purchase Agreement, the Issuer (with respect to its reserved rights) or the Trustee where so provided, but subject to the statutory limitations on remedies against Bonneville, may take whatever action at law or in equity permitted by law to be taken against Bonneville as may appear necessary or desirable to collect the amounts then due and thereafter to become due under the Lease-Purchase Agreement.

Any amounts collected pursuant to action taken under this paragraph will be paid to the Trustee for deposit into the Bond Fund and applied in accordance with the provisions of the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the provisions of the Indenture) to Bonneville.

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease-Purchase Agreement. The Issuer and Bonneville declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer waives any rights it may have as a secured party with respect to the Project.

Statutory Limitation on Legal Remedies against Bonneville

The Issuer acknowledges in the Lease-Purchase Agreement that its remedies against Bonneville are limited to those provided under federal law, which provides that the exclusive remedy for breach of contract by Bonneville is a judgment for money damages. The Issuer and Bonneville have agreed that such damages shall be measured by the amounts required to be paid by Bonneville under the Lease-Purchase Agreement and not by the market value of the Project or a leasehold interest in the Project.

Options

Under the Lease-Purchase Agreement, Bonneville has the option, at any time and from time to time, to make advance rental payments which, at the direction of Bonneville, will be deposited into the Bond Fund and held to make the next maturing scheduled payments of principal and interest on the Bonds or applied to redeem all or a portion of the Bonds, all in accordance with the terms of the Indenture. Bonneville has the option, at any time and from time to time, to purchase all or any portion of the Project by making a purchase option payment equal to the amount necessary to redeem all or the applicable portion of the Bonds on the next redemption date. Such purchase option may be assigned by Bonneville without the consent of the Issuer. The Project is divided into components as provided in the Lease-Purchase Agreement and Bonneville may exercise its purchase option with respect to any component or portion thereof by making a purchase option payment equal to the redemption price of the percentage of Bonds of the applicable maturity of the Bonds allocable to such component or portion. Bonneville or its assignee will exercise its option to make such advance rental payments or such purchase option by delivering a written notice of an authorized representative of Bonneville to the Trustee in accordance with the Indenture, with a copy to the Issuer, setting forth (i) the amount of the advance rental payment or purchase option payment, (ii) the principal amount of Bonds Outstanding requested to be redeemed with such advance rental payment (if any) or purchase option payment (which principal amount shall be in such minimum amount or integral multiple of such amount as shall be permitted in the Indenture), and (iii) the date on which such principal amount of Bonds are to be redeemed. Such advance rental payment to be applied to redeem Bonds or to make any such purchase option payment will be paid to the Trustee in legal tender on or before the redemption date and will be an amount which, when added to the amount on deposit in the Bond Fund and available therefor, will be sufficient to pay the Redemption Price of the Bonds to be redeemed, together with interest to accrue on the Bonds to be redeemed to the date fixed for redemption and all expenses of the Issuer, the Bond Registrar, the Trustee and the Paying Agents (including reasonable fees and expenses of counsel to the Issuer, the Bond Registrar, the Trustee and the Paying Agents) in connection with such redemption. After any purchase of a portion of the Project, the rental payment payable pursuant to the Lease-Purchase Agreement will be reduced by the percentage equal to the percentage that the portion of the Project purchased is to the entire Project (as shown in a schedule to the Lease-Purchase Agreement) or by such other amount agreed to by the Issuer and Bonneville with the consent of the Trustee; provided that, in either case, such amount may not be less than an amount sufficient to pay debt service on the Outstanding Bonds when due.

Bonneville may assign to another entity the options described in the preceding paragraph provided that all other provisions relating to the exercise of the options, including the provisions describe above, shall be complied with upon exercise of the options. It is possible that Bonneville could enter into a new lease-purchase agreement with the assignee of the option(s), and the assignee could exercise the option(s) to purchase or pre-pay all or a portion of the properties constituting the Project. In this circumstance, the assignee of the option(s) could pledge rental payments from Bonneville under the new lease to secure the issuance of debt the proceeds of which would be used to fund the pre-payment or purchase occasioned by the exercise of the option(s).

Force Majeure

The obligations of the parties under the Lease-Purchase Agreement, except the obligation of Bonneville to make payments required to be made under the Lease-Purchase Agreement and to indemnify the Issuer, are subject to suspension during periods of force majeure.

Assignment or Sublease

Bonneville may assign, partially assign (for instance, Bonneville may assign the Lease with respect to certain identified portions of the Project) or transfer the Lease-Purchase Agreement or sublet the whole or any part of the Project so long as Bonneville will remain liable to the Issuer for the payment of all rental payments and other payments under the Lease-Purchase Agreement and for the full performance of all of the terms, covenants and conditions of the Lease. Bonneville will furnish or cause to be furnished to the Issuer a copy of any such assignment, transfer or sublease in substantially final form within ten (10) days prior to the date of execution thereof. Bonneville may also enter into contracts relating to the use of the Project as provided in the Lease-Purchase Agreement. Funds received by or on account of Bonneville in connection with a sublease, assignment, partial assignment or transfer in accordance with this paragraph shall be Bonneville's funds.

Amendment

The Lease-Purchase Agreement may not be amended except by an instrument in writing signed by Bonneville and the Issuer and consented to by the Trustee in accordance with the Indenture. See “THE INDENTURE - Amendment of the Lease-Purchase Agreement.” A change in the definition of the Project pursuant to the Lease-Purchase Agreement will not constitute an amendment to the Lease-Purchase Agreement. See “THE LEASE-PURCHASE AGREEMENT – Changing the Definition of the Project.”

Changing the Definition of the Project

Under the Lease-Purchase Agreement and the Indenture, the definition of the Project may be amended from time to time, without the consent of the holders of the Bonds, including to exclude components or portions thereof or to add other facilities; provided, however, that, Bonneville’s rental payments shall remain unaffected by such a change in definition. By means of changing the definition of the Project, it is possible that, among other things, facilities that were once portions of the Project may be excluded from the definition and transferred to Bonneville’s ownership, or transferred to another entity’s ownership, but in any such instance the Lease-Purchase Agreement shall remain valid, binding and enforceable against Bonneville and there shall be no abatement, postponement or reduction in the rental payments or other amounts payable by Bonneville under the Lease-Purchase Agreement.

More particularly, the Issuer will commit to agree that, at the request of Bonneville, it will amend the definition of a Project (i) to change the location of the Project or any component or portion thereof, (ii) to remove any part of the Project, or (iii) to replace all or any part of such Project with facilities having a comparable value. The Project definition may be otherwise amended as may be agreed to by the Issuer and Bonneville. The amendment of the Project definition shall not entitle Bonneville to any abatement or reduction in the rentals and other amounts payable by Bonneville under the Lease-Purchase Agreement. In the event of a re-definition of the Project, there is no obligation or special right to call any of the Bonds prior to their final maturity. The right of Issuer and Bonneville to change the definition of the Project is separate and apart from the amendment of the Lease-Purchase Agreement. See “THE LEASE-PURCHASE AGREEMENT – Amendment,” and “THE INDENTURE – Amendment of the Lease-Purchase Agreement.”

If a portion of the Project becomes obsolete, worn-out, or otherwise is taken out of service or retired prior to the final maturity of the Bonds, the Project may be re-defined to remove such portions of the Project through an amendment to the definition of the Project. See “Sale, Assignment, or Other Dispositions of Portions of the Project” below. If such portion of the Project is replaced, the facilities so replacing the portion may be owned by Bonneville or another project owner or replaced with funds obtained by the Issuer under a lease with Bonneville separate and apart from the Lease-Purchase Agreement. See “THE PROJECT.”

Sale, Assignment, or Other Dispositions of Portions of the Project

As described above, the definition of the Project may be amended from time to time to remove of any part of the Project. See "Changing the Definition of the Project” above. Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired and Bonneville shall not be required to deposit in the Bond Fund or otherwise pay to the Issuer any amounts received by Bonneville from such sale, assignment or disposition. When removing any part of the Project which is obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired, Bonneville may notify the Issuer that such portion no longer constitutes part of the Project and effective upon such notice the definition of the Project will be deemed so amended (the removal may also be effected through an amendment). Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is not obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired and the funds received from such sale, assignment or disposition shall be paid over to the Bond Fund to be applied to the payment of principal of, and interest and premiums, if any, on, the Bonds, and to the extent the amounts are so applied, they will constitute a contribution to rental payments otherwise payable by Bonneville.

THE INDENTURE

The following is a summary of certain provisions of the Indenture, to which reference is made for the detailed provisions thereof.

Trust Estate

Pursuant to the Indenture, (i) all of the Issuer's right, title and interest in and to the Lease-Purchase Agreement, including all amounts (excluding payments for indemnification and certain other payments thereunder) to be received by the Issuer pursuant to the Lease-Purchase Agreement, (ii) all of the right, title and interest of the Issuer in and to the Project, (iii) all moneys and securities held by the Trustee under the Indenture including amounts held by the Trustee in the Project Fund, the Bond Fund and the Reserve Fund established under the Indenture, and (iv) any and all other property that may be conveyed to the Trustee as security for the Bonds, are assigned and pledged to the Trustee to secure the payment of the principal of, premium, if any, and interest on the Bonds.

Project Fund

The proceeds of the sale of the Series 2024 Bonds will be deposited in the Project Fund to be held by the Trustee. Moneys in the Project Fund will be applied to pay a loan that was used to finance the costs of acquisition and construction of the Project, and to pay expenses incurred in connection with the issuance and sale of the Series 2024 Bonds, and for other costs of the Project upon requisitions signed by an authorized representative of Bonneville or, with respect to certain costs of issuance, an authorized representative of the Issuer.

Bond Fund

The Indenture establishes with the Trustee a Bond Fund into which will be deposited accrued interest, lease rental payments paid by Bonneville and other receipts to be paid into the Bond Fund. The Bond Fund will be used (except as otherwise provided in the Indenture) for the payment of principal of, premium, if any, and interest on the Bonds.

Reserve Fund

The Indenture establishes with the Trustee a Reserve Fund into which will be deposited any amounts remaining on deposit in the Bond Fund on the Business Day following each interest payment date on the Bonds. The Reserve Fund will be used for the payment of amounts payable by or to the Issuer upon requisitions signed by an authorized representative of the Issuer. There is no requirement in the Indenture that withdrawals from the Reserve Fund be replenished or that the Reserve Fund be maintained at a particular amount.

Investments

Amounts in any fund or account established under the Indenture may be invested or reinvested by the Trustee upon the written direction of an authorized representative of the Issuer at the direction of Bonneville in obligations or securities specified in the Indenture.

Additional Bonds

So long as the Lease-Purchase Agreement is in effect, Additional Bonds may be issued under the Indenture from time to time in the discretion of the Issuer for the purpose of (i) providing funds to repair, relocate, replace, rebuild or restore the Project in the event of damage, destruction or taking by eminent domain, (ii) providing extensions, additions or improvements to the Project, or (iii) refunding outstanding Bonds. It is a condition to the issuance of Additional Bonds that the amounts payable by Bonneville under the Lease-Purchase Agreement will be adjusted to provide for the payment of principal of, premium, if any, and interest on the Additional Bonds. Additional Bonds shall be equally and ratably secured under the Indenture with the Series 2024 Bonds.

Events of Default and Remedies

Each of the following is an "Event of Default" under the Indenture:

(a) failure in the payment of interest on any Bond when due;

(b) failure in the payment of the principal or redemption premium, if any, of, or sinking fund installment for, any Bond when due, whether at the stated maturity thereof, upon any proceedings for redemption thereof or otherwise;

(c) failure by the Issuer to perform or observe any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds (except as set forth in (a) or (b) above), and the continuance thereof for a period of thirty days after written notice to the Issuer and Bonneville from the Trustee or the holders of more than 25% of the aggregate principal amount of Bonds then outstanding; provided that, if the default can be remedied but not within the applicable period, the Issuer or Bonneville proceeds with diligence to cure the default, it shall not be an Event of Default; or

(d) an Event of Default under the Lease-Purchase Agreement.

Pursuant to the Lease-Purchase Agreement, the Issuer has granted to Bonneville full authority for the account of the Issuer to perform any covenant or obligation the non-performance of which is alleged in any notice received by Bonneville to constitute a default under the Indenture, in the name and stead of the Issuer with full power to do any and all things and acts to the same extent that the Issuer could do and perform any such things and acts with power of substitution. The Trustee agrees to accept such performance by Bonneville as performance by the Issuer.

Upon the occurrence and continuance of an Event of Default, the Trustee may, and at the direction of the holders of over 25% of the outstanding Bonds shall, take actions at law or equity to protect and enforce its rights and the rights of the Bondholders. If requested by the holders of over 25% of the outstanding Bonds, the Trustee shall maintain actions to prevent impairment of the security of the Indenture whether or not there has occurred an Event of Default. **The Indenture does not provide for the remedy of acceleration of payment of the Bonds.**

The holders of a majority in aggregate principal amount of Bonds then outstanding have the right, at any time, by an instrument or instruments in writing delivered to the Trustee, to direct the method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceeding under the Indenture; provided, that such direction shall not be otherwise than in accordance with the provisions of law and the Indenture.

No holder of any Bond shall have any right to institute any suit, action or proceeding in equity or at law for the enforcement of the Indenture or for the execution of any trust thereof or any remedy under the Indenture, unless the Trustee has been notified of the default, and the holders of over 25% of aggregate principal amount of Bonds then outstanding have made a written request to the Trustee and have offered reasonable opportunity either to exercise the powers granted in the Indenture or to institute such action, suit or proceeding in its own name, and unless they also have offered to the Trustee adequate security and indemnity and the Trustee refuses to comply within 60 days. Nothing in the Indenture shall, however, affect or impair the right of any Bondholder to payment of the principal or redemption price, if applicable, of, sinking fund installments for, and interest on any Bond at and after the maturity thereof, or the obligation of the Issuer to pay the principal or redemption price, if applicable, of, sinking fund installments for, and interest on the Bonds to the respective holders thereof at the time, place, from the source and in the manner expressed in the Bonds and the Indenture.

Waivers of Events of Default

The Trustee shall waive any Event of Default under the Indenture and its consequences only upon the written request of the holders of a majority in aggregate principal amount of the Bonds then outstanding; provided, however, that there shall not be waived without the consent of the holders of all of the Bonds then outstanding (i) any default in the payment of the principal of any outstanding Bond when due or (ii) any default in the payment when due of the interest on any outstanding Bond, unless, prior to such waiver, all arrears of interest, with interest (to the extent permitted by law) at the rate borne by the Bonds on overdue installments of interest, and all arrears of payments of principal, when due, as the case may be, and all expenses of the Trustee in connection with such default, shall have been paid or provided for, or in case any proceeding taken by the Trustee on account of any such default shall have been discontinued or abandoned or determined adversely, then, and in every such case the Issuer, the Trustee, Bonneville and the Bondholders shall be restored to their former positions and rights under the Indenture, respectively, but no such waiver or rescission shall extend to any subsequent or other Event of Default, or impair any right consequent thereon.

Application of Moneys after Default

All moneys received by the Trustee pursuant to any right given or action taken under the provisions of the Indenture shall, after payment of any amounts due under the Lease-Purchase Agreement and after the payment of the costs and expenses of the proceedings resulting in the collection of such moneys and of the fees, expenses, liabilities and advances incurred or made by the Trustee, be deposited in the Bond Fund. Such amounts will be applied first to the payment of interest and then to the payment of principal or redemption price, if any, which shall have become due.

Amendments of the Indenture

The Issuer and the Trustee may, without the consent of, or notice to, the Bondholders, enter into indentures supplemental to the Indenture (a) to cure any ambiguity or formal defect or omission in the Indenture; (b) to grant to or confer upon the Trustee for the benefit of the Bondholders any additional rights, remedies, powers, authority or security that may be lawfully granted; (c) to add additional covenants of the Issuer; (d) to add limitations and restrictions to be observed by the Issuer; which are not contrary to or inconsistent with the Indenture as theretofore in effect; (e) to confirm, as further assurance, any pledge under the Indenture, or to subject to the lien or pledge of the Indenture additional revenues, properties or collateral; (f) to effect any other change in the Indenture which is not to the material prejudice of the Trustee or the Bondholders; (g) to authorize the issuance of a Series of Additional Bonds; or (h) to modify, amend or supplement the Indenture or any indenture supplemental thereto in such manner as to permit the qualification thereof under the Trust Indenture Act of 1939 or any similar federal statute then in effect or to permit the qualification of the Bonds for sale under the securities laws of the United States of America or of any of the states of the United States of America and, if they so determine, to add to the Indenture or any indenture supplemental thereto such other terms, conditions and provisions as may be permitted by the Trust Indenture Act of 1939 or similar federal statute.

With the consent of Bonneville and the holders of not less than a majority in aggregate principal amount of the Bonds then outstanding, the Issuer and the Trustee may enter into such other supplemental indentures as the Issuer shall deem necessary and desirable, provided there shall be no (i) change in the times, amounts or currency of payment of the principal of, sinking fund installments for, redemption premium, if any, or interest on any outstanding Bonds, a change in the terms of redemption or maturity of the principal of or the interest on any outstanding Bonds, or a reduction in the principal amount of or the redemption price of any outstanding Bond or the rate of interest thereon, or any extension of the time of payment thereof, without the consent of the holder of such Bond, (ii) the creation of a lien upon or pledge of the Trust Estate other than the liens or pledge created by the Indenture except as provided in the Indenture with respect to Additional Bonds, (iii) a preference or priority of any Bond or Bonds over any other Bond or Bonds, (iv) a reduction in the aggregate principal amount of Bonds required for consent to such supplemental indenture, or (v) a modification, amendment or deletion with respect to any of the terms set forth above, without, in the case of items (ii) through (v) above, the written consent of 100% of the holders of the outstanding Bonds.

Amendment of the Lease-Purchase Agreement

The Issuer and the Trustee may, without the consent of or notice to the Bondholders, consent to any amendment, change or modification of the Lease-Purchase Agreement (a) for the purpose of curing any ambiguity, formal defect or omission therein, (b) which, by the terms of the Lease-Purchase Agreement, may be made without the consent of the Bondholders, or (c) which is not materially to the prejudice of the Trustee or the Holders of the Bonds. The Trustee shall not consent to any other amendment, change or modification of the Lease-Purchase Agreement without the consent of the holders of at least a majority in principal amount of the Bonds then outstanding, provided, however, that without the written approval of the holders of 100% of the Bonds, there shall be no amendment, change or modification to the obligation of Bonneville to make rental payments under the Lease-Purchase Agreement with respect to the Bonds. Separate and apart from the amendment of the Lease-Purchase Agreement, the Issuer and Bonneville will reserve the right to amend the definition of the Project. See THE LEASE-PURCHASE AGREEMENT – Changing the Definition of the Project."

Discharge of the Indenture

If the principal or redemption price of, sinking fund installments for, and interest on, the Bonds then outstanding shall have been paid in full or shall be deemed to have been paid in full, and all other amounts required to be paid to the Trustee under the Indenture shall be paid in full, then the pledge of any lease rentals, revenues or receipts from or in connection with the Project under the Indenture shall cease, terminate and be void and the Trustee shall cancel and discharge the lien and security interest of the Indenture and execute and deliver to the Issuer and Bonneville such instruments as shall be required to cancel and discharge the Indenture and pay over and deliver to the Issuer all money or securities held by it not required for payment of the Bonds.

Bonds or portions thereof for the payment (either by redemption or at maturity) of which sufficient moneys shall have been irrevocably deposited with the Trustee, shall be deemed to be paid within the meaning of the Indenture if (A) there shall have been deposited with the Trustee either moneys in an amount which shall be sufficient, or obligations of the United States government or obligations the principal of and interest on which are guaranteed by the United States government, the principal of and the interest on which when due without reinvestment will provide moneys which, together with the moneys, if any, deposited with the Trustee at the same time, shall be sufficient, to pay when due the principal, Sinking Fund Installment or Redemption Price, if applicable, and interest due and to become due on said Bonds or portion of all Outstanding Bonds on and prior to the redemption date or maturity date thereof, as the case may be; (B) no Event of Default shall exist on the date of such deposit or shall occur as a result of such deposit; and (C) the Issuer has delivered to the Trustee and any Paying Agent a certificate signed by an Authorized Representative and an opinion of counsel, each stating that the conditions set forth in subsections (A) and (B) above have been complied with.

CONTINUING DISCLOSURE

Bonneville, as an "obligated person" within the meaning of Section (b)(5)(i) of Securities and Exchange Commission Rule 15c2-12 under the Securities Exchange Act of 1934, as amended (17 CFR Part 240, § 240.15c2-12) (the "Rule"), has undertaken in the Continuing Disclosure Certificate to provide certain information. A copy of the form of Continuing Disclosure Certificate is contained in Appendix D herein.

Bonneville has not failed to comply with all previous undertakings with respect to the Rule in any material respect in the preceding five years. The information to be provided in the Annual Information and the notices of such material events are set forth in Appendix D "FORM OF CONTINUING DISCLOSURE CERTIFICATE."

The Issuer has not undertaken any continuing disclosure obligation with respect to the Bonds.

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2024 Bonds.

RATINGS

Moody's Investors Service ("Moody's") and Fitch Ratings ("Fitch") have assigned the Series 2024 Bonds the ratings of "Aa1" (negative outlook) and "AA" (stable outlook), respectively. Ratings were applied for by Bonneville and certain information was supplied by Bonneville to such rating agencies to be considered in evaluating the Series 2024 Bonds. Such ratings reflect only the respective views of such rating agencies, and an explanation of the significance of such ratings may be obtained only from the rating agency furnishing the same. There is no assurance that any or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Series 2024 Bonds.

UNDERWRITING

Wells Fargo Bank, National Association and the other Underwriters (the "Underwriters") of the Series 2024 Bonds have jointly and severally agreed, subject to certain conditions, to purchase the Series 2024 Bonds from the Issuer at an underwriters' discount of $278,659.36 and to reoffer the Series 2024 Bonds at the initial public offering price set forth on the cover page hereof. The Underwriters have agreed to purchase all of the Series 2024 Bonds if any are purchased.

The Series 2024 Bonds may be offered and sold to certain dealers (including dealers depositing Series 2024 Bonds into investment accounts) and to others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Series 2024 Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriters. Bonneville has agreed to pay certain out-of-pocket expenses of the Underwriters, which are included in the discount set forth above.

Wells Fargo Securities is the trade name for certain securities-related capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including Wells Fargo Bank, National Association, which conducts its municipal securities sales, trading and underwriting operations through the Wells Fargo Bank, NA Municipal Finance Group, a separately identifiable department of Wells Fargo Bank, National Association, registered with the Securities and Exchange Commission as a municipal securities dealer pursuant to Section 15B(a) of the Securities Exchange Act of 1934.

Certain of the Underwriters have entered into distribution agreements with other broker-dealers for the distribution of the Series 2024 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 have provided the following information for inclusion in this Official Statement. The Underwriters and their affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. See herein "CERTAIN RELATIONSHIPS." The Underwriters and their affiliates have, from time to time, performed, and may in the future perform, various investment banking services for Bonneville for which they received or will receive customary fees and expenses. In the ordinary course of their various business activities, the Underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve securities and instruments secured by payments from Bonneville.

CERTAIN RELATIONSHIPS

Wells Fargo Bank, National Association, an Underwriter of the Series 2024 Bonds, has extended credit in other transactions supported by obligations of Bonneville under related agreements.

A portion of the proceeds of the Series 2024 Bonds will be used to pay off an extension of credit made to the Issuer by Wells Fargo Bank, National Association.

BofA Securities, Inc., an Underwriter of the Series 2024 Bonds, is an affiliate of Bank of America, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

TD Securities (USA) LLC, an Underwriter of the Series 2024 Bonds, is an affiliate of TD Bank, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

TAX MATTERS

At the closing, Special Counsel is expected to deliver its opinion, based upon an analysis of existing laws, regulations, rulings and court decisions, that, interest on the Series 2024 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the Code. In the opinion of Special Counsel, interest on the Series 2024 Bonds is exempt from State of Oregon personal income taxes. Special Counsel is expected to express no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual, or receipt of interest on, the Series 2024 Bonds.

The following discussion summarizes certain U.S. federal income tax considerations generally applicable to holders of the Series 2024 Bonds that acquire their Series 2024 Bonds in the initial offering. The discussion below is based upon laws, regulations, rulings, and decisions in effect and available on the date hereof, all of which are subject to change, possibly with retroactive effect. Prospective investors should note that no rulings have been or are expected to be sought from the U.S. Internal Revenue Service (the “IRS”) with respect to any of the U.S. federal income tax considerations discussed below, and no assurance can be given that the IRS will not take contrary positions. Further, the following discussion does not deal with U.S. tax consequences applicable to any given investor, nor does it address the U.S. tax considerations applicable to all categories of investors, some of which may be subject to special taxing rules (regardless of whether or not such investors constitute U.S. Holders), such as certain U.S. expatriates, banks, REITs, RICs, insurance companies, tax-exempt organizations, dealers or traders in securities or currencies, partnerships, S corporations, estates and trusts, or investors that hold their Series 2024 Bonds as part of a hedge, straddle or an integrated or conversion transaction, or investors whose “functional currency” is not the U.S. dollar or certain taxpayers that are required to prepare certified financial statements or file financial statements with certain regulatory or governmental agencies. Furthermore, it does not address (i) alternative minimum tax consequences, (ii) the net investment income tax imposed under Section 1411 of the Code, or (iii) the indirect effects on persons who hold equity interests in a holder. This summary also does not consider the taxation of the Series 2024 Bonds under state, local or non-U.S. tax laws. In addition, this summary generally is limited to U.S. federal income tax considerations applicable to investors that acquire their Series 2024 Bonds pursuant to this offering for the issue price that is applicable to such Series 2024 Bonds (i.e., the price at which a substantial amount of the Series 2024 Bonds are sold to the public) and who will hold their Series 2024 Bonds as “capital assets” within the meaning of Section 1221 of the Code.

As used herein, “U.S. Holder” means a beneficial owner of a Series 2024 Bond that for U.S. federal income tax purposes is an individual citizen or resident of the United States, a corporation or other entity taxable as a corporation created or organized in or under the laws of the United States or any state thereof (including the District of Columbia), an estate the income of which is subject to U.S. federal income taxation regardless of its source or a trust where a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons (as defined in the Code) have the authority to control all substantial decisions of the trust (or a trust that has made a valid election under U.S. Treasury Regulations to be treated as a domestic trust). As used herein, “Non-U.S. Holder” generally means a beneficial owner of a Series 2024 Bond (other than a partnership) that is not a U.S. Holder. If a partnership holds Series 2024 Bonds, the tax treatment of such partnership or a partner in such partnership generally will depend upon the status of the partner and upon the activities of the partnership. Partnerships holding Series 2024 Bonds, and partners in such partnerships, should consult their own tax advisors regarding the tax consequences of an investment in the Series 2024 Bonds (including their status as U.S. Holders or Non-U.S. Holders).

Prospective investors should consult their own tax advisors in determining the U.S. federal, state, local or non-U.S. tax consequences to them from the purchase, ownership and disposition of the Series 2024 Bonds in light of their particular circumstances.

U.S. Holders

Interest. Interest on the Series 2024 Bonds generally will be taxable to a U.S. Holder as ordinary interest income at the time such amounts are accrued or received, in accordance with the U.S. Holder's method of accounting for U.S. federal income tax purposes.

To the extent that the issue price of any maturity of the Series 2024 Bonds is less than the amount to be paid at maturity of such Series 2024 Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2024 Bonds) by more than a de minimis amount, the difference may constitute original issue discount ("OID"). U.S. Holders of Series 2024 Bonds will be required to include OID in income for U.S. federal income tax purposes as it accrues, in accordance with a constant yield method based on a compounding of interest (which may be before the receipt of cash payments attributable to such income). Under this method, U.S. Holders generally will be required to include in income increasingly greater amounts of OID in successive accrual periods.

Series 2024 Bonds purchased for an amount in excess of the principal amount payable at maturity (or, in some cases, at their earlier call date) will be treated as issued at a premium. A U.S. Holder of a Series 2024 Bond issued at a premium may make an election, applicable to all debt securities purchased at a premium by such U.S. Holder, to amortize such premium, using a constant yield method over the term of such Series 2024 Bond.

Sale or Other Taxable Disposition of the Series 2024 Bonds. Unless a nonrecognition provision of the Code applies, the sale, exchange, redemption, retirement (including pursuant to an offer by the Issuer) or other disposition of a Series 2024 Bond will be a taxable event for U.S. federal income tax purposes. In such event, in general, a U.S. Holder of a Series 2024 Bond will recognize gain or loss equal to the difference between (i) the amount of cash plus the fair market value of property received (except to the extent attributable to accrued but unpaid interest on the Series 2024 Bond, which will be taxed in the manner described above) and (ii) the U.S. Holder's adjusted U.S. federal income tax basis in the Series 2024 Bond (generally, the purchase price paid by the U.S. Holder for the Series 2024 Bond, decreased by any amortized premium and increased by the amount of any OID previously included in income by such U.S. Holder with respect to such Series 2024 Bond). Any such gain or loss generally will be capital gain or loss. In the case of a non-corporate U.S. Holder of the Series 2024 Bonds, the maximum marginal U.S. federal income tax rate applicable to any such gain will be lower than the maximum marginal U.S. federal income tax rate applicable to ordinary income if such U.S. holder's holding period for the Series 2024 Bonds exceeds one year. The deductibility of capital losses is subject to limitations.

Defeasance of the Series 2024 Bonds. If the Issuer defeases any Series 2024 Bond, the Series 2024 Bond may be deemed to be retired and "reissued" for U.S. federal income tax purposes as a result of the defeasance. In that event, in general, a holder will recognize taxable gain or loss equal to the difference between (i) the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and (ii) the holder's adjusted U.S. federal income tax basis in the Series 2024 Bond. See "THE INDENTURE – Discharge of the Indenture."

Information Reporting and Backup Withholding. Payments on the Series 2024 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 U.S. Holder of the Series 2024 Bonds may be subject to backup withholding at the current rate of 24% with respect to "reportable payments," which include interest paid on the Series 2024 Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the Series 2024 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 the U.S. Holder's federal income tax liability, if any, provided that the required information is timely furnished to the IRS. Certain U.S. holders (including among others, corporations and certain tax-exempt organizations) are not subject to backup withholding. A holder's failure to comply with the backup withholding rules may result in the imposition of penalties by the IRS.

Non-U.S. Holders

Interest. Subject to the discussions below under the headings "Information Reporting and Backup Withholding" and "Foreign Account Tax Compliance Act ("FATCA")—U.S. Holders and Non-U.S. Holders," payments of principal of, and interest on, any Series 2024 Bond to a Non-U.S. Holder, other than (1) a controlled foreign corporation described in Section 881(c)(3)(C) of the Code, and (2) a bank which acquires such Series 2024 Bond in consideration of an extension of credit made pursuant to a loan agreement entered into in the ordinary course of business, will not be subject to any U.S. federal withholding tax provided that the beneficial owner of the Series 2024 Bond provides a certification completed in compliance with applicable statutory and regulatory requirements, which requirements are discussed below under the heading "Information Reporting and Backup Withholding," or an exemption is otherwise established.

Disposition of the Series 2024 Bonds. Subject to the discussions below under the headings "Information Reporting and Backup Withholding" and "Foreign Account Tax Compliance Act ("FATCA")—U.S. Holders and Non-U.S. Holders," any gain realized by a Non-U.S. Holder upon the sale, exchange, redemption, retirement (including pursuant to an offer by the Issuer or a deemed retirement due to defeasance of the Series 2024 Bond) or other disposition of a Series 2024 Bond generally will not be subject to U.S. federal income tax, unless (i) such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business within the United States; or (ii) in the case of any gain realized by an individual Non-U.S. Holder, such holder is present in the United States for 183 days or more in the taxable year of such sale, exchange, redemption, retirement (including pursuant to an offer by the Issuer) or other disposition and certain other conditions are met.

Information Reporting and Backup Withholding. Subject to the discussion below under the heading "FATCA," under current U.S. Treasury Regulations, payments of principal and interest on any Series 2024 Bonds to a holder that is not a United States person will not be subject to any backup withholding tax requirements if the beneficial owner of the Series 2024 Bond or a financial institution holding the Series 2024 Bond on behalf of the beneficial owner in the ordinary course of its trade or business provides an appropriate certification to the payor and the payor does not have actual knowledge that the certification is false. If a beneficial owner provides the certification, the certification must give the name and address of such owner, state that such owner is not a United States person, or, in the case of an individual, that such owner is neither a citizen nor a resident of the United States, and the owner must sign the certificate under penalties of perjury. The current backup withholding tax rate is 24%.

Foreign Account Tax Compliance Act ("FATCA")—U.S. Holders and Non-U.S. Holders

Sections 1471 through 1474 of the Code impose a 30% withholding tax on certain types of payments made to foreign financial institutions, unless the foreign financial institution enters into an agreement with the U.S. Treasury to, among other things, undertake to identify accounts held by certain U.S. persons or U.S.-owned entities, annually report certain information about such accounts, and withhold 30% on payments to account holders whose actions prevent it from complying with these and other reporting requirements, or unless the foreign financial institution is otherwise exempt from those requirements. In addition, FATCA imposes a 30% withholding tax on the same types of payments to a non-financial foreign entity unless the entity certifies that it does not have any substantial U.S. owners or the entity furnishes identifying information regarding each substantial U.S. owner. Under current guidance, failure to comply with the additional certification, information reporting and other specified requirements imposed under FATCA could result in the 30% withholding tax being imposed on payments of interest on the Bonds. In general, withholding under FATCA currently applies to payments of U.S. source interest (including OID) and, under current guidance, will apply to certain "passthru" payments no earlier than the date that is two years after publication of final U.S. Treasury Regulations defining the term "foreign passthru payments." Prospective investors should consult their own tax advisors regarding FATCA and its effect on them.

The foregoing summary is included herein for general information only and does not discuss all aspects of U.S. federal taxation that may be relevant to a particular holder of Series 2024 Bonds in light of the holder's particular circumstances and income tax situation. Prospective investors are urged to consult their own tax advisors as to any tax consequences to them from the purchase, ownership and disposition of Series 2024 Bonds, including the application and effect of state, local, non-U.S., and other tax laws.

LEGAL MATTERS

Legal matters incident to the authorization and issuance of the Series 2024 Bonds are subject to the unqualified approving opinion of Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Issuer by Monahan, Grove & Tucker, Milton-Freewater, Oregon, and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York.

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

TABLE OF CONTENTS

PAGE

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to the Port of Morrow, Oregon (the "Issuer" or the "Port of Morrow") by Bonneville for use in the Official Statement, dated June 6, 2024, of the Issuer (the "Official Statement") with respect to its Transmission Facilities Revenue Bonds, (Bonneville Cooperation Project No. 9), Series 2024 (Federally Taxable) (Green Bonds – Climate Bond Certified) (the "Series 2024 Bonds"). (The Project is described in the Official Statement as "THE PROJECT.") Such information in this Appendix A is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2024 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this Appendix A and in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

This Appendix A contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements." In this respect, the words "forecast," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. A number of important factors affecting Bonneville's business, operations, and financial results could cause actual results to differ materially from those stated in the forward-looking statements. Bonneville does not plan to issue updates or revisions to the forward-looking statements.

This Appendix A contains financial information presented in accordance with accounting principles generally accepted in the United States of America ("GAAP") and certain non-GAAP financial metrics. For a discussion of the non-GAAP financial metrics used by Bonneville, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." Certain tables where GAAP has not been applied are labeled as "unaudited." PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to this information. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any form of assurance with respect to that financial data.

GENERAL

Bonneville was created by an act of Congress in 1937 to market electric power from the Bonneville Dam, which is located on the Columbia River, and to construct facilities necessary to transmit such power. Congress has since designated Bonneville to be the marketing agent for power from all of the federally-owned hydroelectric projects in the Pacific Northwest. Bonneville, whose headquarters are located in Portland, Oregon, is one of four regional federal power marketing agencies within the United States of America, Department of Energy ("DOE"). Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-federally-owned and -operated projects, including an operating nuclear generating station (the "Columbia Generating Station") owned by Energy Northwest (a joint operating agency of Washington State) and having a rated capacity of approximately 1,207 megawatts. (Although the rated capacity of Columbia Generating Station is 1,207 megawatts, Bonneville assumes 1,169 megawatts for long-range planning purposes.) In addition, firm energy from transfers, exchanges, and purchases comprise the remaining portion of Bonneville's electric power resources. Not taking into account estimated power lost through the transmission of electricity from generation sites to load sites ("transmission line losses"), Bonneville estimates that the foregoing projects and contracts have an expected aggregate energy output in Operating Year 2025 of approximately 9,662 annual average megawatts (defined below) under median water conditions and approximately 7,960 annual average megawatts under low water conditions. (Bonneville's "Operating Year" runs from August 1 through July 31. By contrast, its "Fiscal Year" runs from October 1 through September 30.) (Annual average megawatts are the number of megawatt-hours of electric energy used, transmitted, or produced over the course of one (non-leap year) year and each annual average megawatt is equal to 8,760 megawatt-hours.)

Bonneville sells, purchases, and exchanges firm power, seasonal surplus energy peaking capacity, and related power services. Bonneville also constructed, owns and/or possesses, operates, and maintains a high voltage transmission system (the "Federal Transmission System") comprising more than 15,000 circuit miles of high voltage transmission lines in the Pacific Northwest. Bonneville uses these transmission lines to deliver power to its power customers and makes transmission capacity available to other utilities, owners of generation projects, and power marketers. Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada, northern Utah, and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the approximately 300,000 square-mile service area is approximately 15 million people. Electric power sold by Bonneville accounts for approximately 28 percent of the electric power consumed within the Region.

Bonneville markets a large portion of this power to over 125 publicly-owned, cooperatively-owned, and tribal utilities ("Preference Customers") at wholesale, meaning for resale by the utilities to end-use consumers in the Region. Bonneville also has contracts to sell power for direct consumption to several federal agencies and a company ("Direct Service Industrial Customer" or "DSI") located in the Region. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," has resulted and is expected to continue to result in substantial payments by Bonneville to the exchanging utilities. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"), of which there are six. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Proportionately, Preference Customers are the largest customer group to which Bonneville sells power. For example, Bonneville estimated in Fiscal Year 2023 that, on a planning basis in Operating Year 2025, it will meet 7,996 annual average megawatts of loads, of which approximately 87 percent is forecast to be Preference Customer loads, approximately two percent is forecast to be Reclamation loads for irrigation pumping stations, approximately two percent is forecast to be non-Reclamation federal agency loads, less than one percent is forecast to be DSI loads, and approximately nine percent is forecast to be contract deliveries inside and outside the Region. (Actual energy amounts may differ from planned amounts because of energy usage variations due to the weather, end-user behavior, economic activity and other factors.) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Federal System Load/Resource Balance."

The Transmission System Act placed Bonneville on a self-financing basis, meaning that Bonneville pays its costs from revenues it receives from the sale of power and the provision of transmission and other services, which Bonneville provides at rates that seek to produce revenues that recover Bonneville's costs, including certain payments to the United States of America, Department of Treasury (the "United States Treasury"). Bonneville's rates for the foregoing services are subject to approval by the Federal Energy Regulatory Commission ("FERC") on the basis that, among other things, they recover Bonneville's costs. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates." Bonneville may also issue and sell bonds to the United States Treasury and use the proceeds thereof to fund certain activities established under federal law.

In conformity with certain national regulatory initiatives to promote competition in wholesale power markets, in the 1990s Bonneville separated its power marketing function from its transmission system operation and electric system reliability functions. While Bonneville is a single legal entity, it conducts its business as two business units: "Power Services" and "Transmission Services." See "TRANSMISSION SERVICES—FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services."

Bonneville's cash receipts from all sources, including from both Transmission Services operations and Power Services operations, must be deposited in the Bonneville Power Administration Fund (the "Bonneville Fund"), which is a separate fund within the United States Treasury and which is available to pay Bonneville's costs. In accordance with the Transmission System Act, Bonneville must make expenditures from the Bonneville Fund as "shall have been included in annual budgets submitted to Congress, without further appropriation and without fiscal year limitation, but within such specific directives or limitations as may be included in appropriation acts, for any purpose necessary or appropriate to carry out the duties imposed upon [Bonneville] pursuant to law."

Bonneville makes certain payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the facilities of the Federal Columbia River Power System ("Federal System") other than payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest (the "Federal System Hydroelectric Projects"), (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury, (iii) repayments of appropriated amounts to the Corps and Reclamation for certain costs allocated to power generation at Federal System Hydroelectric Projects, and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its scheduled payment responsibility to the United States Treasury of $1.0 billion in full and on time for Bonneville's fiscal year ended September 30, 2023 ("Fiscal Year 2023"). Bonneville has made all payments to the United States Treasury in full and on time since 1984.

For various reasons, Bonneville's revenues from the sale of electric power and other services and its expenses may vary significantly from year to year. In order to accommodate such fluctuations in revenues and expenses and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville including but not limited to lease rental payments for the Project under the Lease-Purchase Agreement, and other operating and maintenance expenses, including net billing cash payments and payments under the direct payment agreements and the costs of electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. For a description of the Lease-Purchase Agreement, see the Official Statement under the heading "THE LEASE-PURCHASE AGREEMENT." In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including lease rental payments for the Project under the Lease-Purchase Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2024 BONDS" and "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. In the event of such a deferral, Bonneville is required to take action, for example by increasing rates or reducing costs, to assure that it has sufficient funds to repay the deferred amounts, with interest, in future years.

Regional Power Sales and Rates

Current Long-Term Preference Contracts

Bonneville's current power sales agreements with Preference Customers are in effect through Fiscal Year 2028 ("Long-Term Preference Contracts"). Virtually all such agreements were executed in 2008 and relate to power sales from Fiscal Year 2012 through Fiscal Year 2028. Under these contracts, Bonneville provides various electric power products primarily to meet the related Preference Customers' own "net requirements" in the Region. Net requirements are the customers' native loads (retail loads within their respective service territories) net of non-Federal System generating resources, if any, designated by a related customer as being used to serve its native loads. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products."

Bonneville sells electric power for Regional load requirements at rates that are established to recover Bonneville's cost of providing such service. Bonneville sells power to Preference Customers and federal agencies, in each case for their requirements, at periodically established "Priority Firm Power Rates" (referred to herein as "PF Preference Rates") that are proposed in advance of the delivery of the power. The PF Preference Rate class is Bonneville's lowest-cost, statutorily-designated, power rate class. PF Preference Rates include separate rate schedules for specific types of service provided to Preference Customers and federal agencies, and the related rate levels vary depending on the costs of providing such services. Beginning in Fiscal Year 2012, PF Preference Rates have been established, and at least through the term of the Long-Term Preference Contracts will be established, on the basis of "Tiered Rates," as discussed below. "Tier 1 PF Rates" apply to a very large portion of the power sales Bonneville makes to Preference Customers, and "Tier 2 PF Rates" apply to a small portion of the power sales Bonneville makes to Preference Customers, essentially for incremental loads above power sold at Tier 1 PF Rates. For a discussion of Tiered Rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." For a discussion of Bonneville's currently applicable power rates, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." The rate for most of the power Bonneville has historically sold to DSIs is the Industrial Firm Power Rate ("IP Rate"), which is based on the PF Preference Rate and certain adjustments required by federal law.

Long-Term Preference Contracts Beginning in Fiscal Year 2029

In anticipation of the expiration of the Long-Term Preference Contracts and other agreements at the end of Fiscal Year 2028, Bonneville has been engaging its customers through a public process to determine the character of Bonneville's long-term power sales commitments in the Region and Bonneville's long-term role in meeting Regional power needs beginning in Fiscal Year 2029. In Fiscal Year 2023, Bonneville continued to hold public workshops to discuss key issues and proposals. In July 2023, Bonneville released a draft policy that reflected the types of products and services that Bonneville plans to offer under new long-term power sales contracts. After taking public comment on the draft policy, Bonneville released a final policy and record of decision on March 21, 2024. This policy will inform the policy implementation and contract development stage which began in April 2024. Through the remainder of Fiscal Year 2024, Bonneville will hold contract negotiation workshops. Bonneville will continue to establish PF Preference Rates on the basis of Tiered Rates and is conducting a parallel process in Fiscal Year 2024 to develop the rate methodology that will be applicable to the new long-term power sales contracts. Bonneville expects to execute new long-term power sales contracts and other agreements by December 2025.

At this time, Bonneville expects to offer similar products and services under the Long-Term Preference Contracts beginning in Fiscal Year 2029 as compared to the current Long-Term Preference Contracts. Bonneville has proposed new flexibilities to allow for customers to add non-federal resources providing customers more opportunities to develop and integrate non-federal resources than compared to current contracts where customers are limited to adding non-federal resources to serve their own load growth. Bonneville will also be discussing how products and services will be compatible with emerging markets, like day-ahead markets, as well as whether it would continue to offer the Slice/Block product. Bonneville cannot predict what changes will be made until the contracts are drafted and executed.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Fiscal Year 2023 Financial Results

In Fiscal Year 2023, Bonneville made its scheduled United States Treasury payments on time and in full for the 40th consecutive year. Bonneville recorded negative net revenues in Fiscal Year 2023 of $257 million, a decrease of approximately $1.2 billion over the prior fiscal year net revenues of $964 million. The decrease in Fiscal Year 2023 year-end agency net revenues is primarily due to: (i) the Power and Transmission Reserves Distribution Clauses that triggered for application to Fiscal Year 2023 rates, which included a $363 million planned decrease in revenues to be collected for the sale of electric power and transmission services due to the rate reductions and (ii) significant purchased power expense that was incurred in Fiscal Year 2023 over amounts forecast when establishing rates for this period. For additional details related to Fiscal Year 2023 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2023." Bonneville finished Fiscal Year 2023 with Total Financial Reserves (as hereinafter defined) of approximately $1.7 billion (Power Services' Total

Financial Reserves of $1.1 billion and Transmission Services' Total Financial Reserves of $627 million), which is a decrease of approximately $107 million, or six percent less than the prior fiscal year. "Total Financial Reserves" is an unaudited metric that is not in accordance with GAAP. Bonneville management believes that the use and reporting of Total Financial Reserves assists in reflecting the financial reserves Bonneville has on hand to meet payment obligations. Bonneville relies on a financial metric it refers to as Reserves Available for Risk ("RAR") as a measure of accumulated cash flow derived from operations. Bonneville divides RAR into "Transmission Services' RAR" and "Power Services' RAR," each of which measures the share of RAR derived from the respective business line's operations. While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations. For a discussion of the non-GAAP financial metrics used by Bonneville, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics."

Bonneville finished Fiscal Year 2023 with RAR of approximately $1.3 billion (Power Services' RAR of approximately $923 million and Transmission Services' RAR of approximately $363 million), a decrease of approximately 15 percent from the prior year. The decrease in Fiscal Year 2023 year-end agency RAR is primarily due to implementation of the Fiscal Year 2023 Reserves Distribution Clause for Power Services and Transmission Services, which resulted in a $350 million decrease in Power Services revenues from gross sales, as discussed above. The year-end RAR balance is equivalent to the amount of cash needed to meet operating expenses for 193 days. Bonneville measures its "Days Cash On Hand" using the following equation: (i) RAR divided by (ii) Operating Expenses (as reported in the "Federal System Statement of Revenues and Expenses") divided by 365. For additional details regarding Bonneville's policies related to financial resiliency, see "BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville Financial Operations"). For additional details related to Fiscal Year 2023 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2023." Based on the Fiscal Year 2023 year-end Power Services and Transmission Services RAR balances, a rate mechanism referred to as the Reserves Distribution Clause (as hereinafter defined) has triggered for application to Power Services and Transmission Services. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Fiscal Year 2024 Expectations

The forward-looking financial information included in this Fiscal Year 2024 Expectations section was not prepared with a view toward compliance with the guidelines of the Securities and Exchange Commission or the guidelines established by the American Institute of Certified Public Accountants for preparation or presentation of prospective financial information.

This forward-looking financial information included in this Fiscal Year 2024 Expectations section has been prepared by, and is the responsibility of, Bonneville's management. PricewaterhouseCoopers LLP has not audited, reviewed, examined, compiled nor applied agreed-upon procedures with respect to the accompanying forward-looking financial information included in this Fiscal Year 2024 Expectations section and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP report included in this document (Appendix B-1 to the Official Statement) relates to Bonneville's previously issued financial statements. It does not extend to the forward-looking financial information included in this Fiscal Year 2024 Expectations section and should not be read to do so.

As of May 23, 2024, Bonneville forecast that it would finish Fiscal Year 2024 with RAR of $720 million (Power Services' RAR of $454 million and Transmission Services' RAR of $266 million), or approximately $567 million less than the $1.3 billion RAR as measured as of the end of Fiscal Year 2023. The forecast decrease in Fiscal Year 2024 RAR is primarily attributable to: (i) the Power and Transmission Reserves Distribution Clauses that triggered for application to Fiscal Year 2024 rates, which includes a $165 million planned decrease in revenues to be collected for the sale of electric power due to the rate reduction and an additional $250 million that has been set aside for other designated power or transmission purposes (see "—Bonneville Power and Transmission Rates Developments") and (ii) significant purchased power expense that has been incurred through March 31, 2024 over amounts forecast when establishing rates for this period, including from the January 2024 cold snap and ice storm, poor water conditions and high power prices. If Bonneville's RAR levels fall below an established threshold, certain rate level adjustment mechanisms are available to increase power or transmission rates and revenues in Fiscal Year 2025. For more details on the thresholds for triggering a Cost Recovery Adjustment Clause (as defined below) or Financial Reserves Policy Surcharge (as defined below), see "—Bonneville Power and Transmission Rates Developments." In addition, the portion of the Fiscal Year 2023 Power RDC (as defined below) being held in Total Financial Reserves for debt reduction in the amount of $90 million could also be made available to support Bonneville's liquidity, if needed.

Forecasts of fiscal year-end results are based on numerous uncertain variables, including but not limited to hydroelectric and water conditions and the level and volatility of market prices for electric power, and are subject to change.

Based on Total Financial Reserves levels and forecasts of revenues and expenses and liquidity tools available, Bonneville believes that it will meet its Fiscal Year 2024 United States Treasury payment obligation on time and in full.

Bonneville Power and Transmission Rates Developments

To establish rates of general applicability for electric power and for transmission and related services, on July 28, 2023, after concluding formal administrative ratemaking processes, Bonneville submitted to FERC for confirmation and approval a final rate proposal for electric power and transmission rates of general applicability for Fiscal Year 2024 and Fiscal Year 2025 (the "2024-2025 Rate Period") in accordance with the Northwest Power Act and other laws. FERC confirms and approves Bonneville's rates after a finding that such rates recover all of Bonneville's costs during the rate period and are sufficient to meet Bonneville's obligations, including debt service on the Series 2024-Bonds and other Lease-Purchase Program Bonds. On March 6, 2024, FERC granted final confirmation and approval of such rates (the "Final 2024-2025 Rates"). Upon final FERC review, the rates may be challenged in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which has original jurisdiction over many Bonneville actions.

The Final 2024-2025 Rates reflect a decrease in power base rates on average and an increase in transmission rates over rates in the immediately preceding two-year rate period (the "2022-2023 Rate Period"). Average Tier 1 PF Rates decreased by less than 1 percent, to $34.69 per megawatt hour, and the average Tier 2 PF Rates increased by 83 percent, to $61.50 when compared to Average Tier 1 and 2 PF Rates in effect in the prior rate period. For more details regarding the average Tier 2 PF Rate increase, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Comparison of Tier 1 PF Rates and Tier 2 PF Rates." There was no change in the weighted average transmission rates, when compared to average rates in effect in the prior rate period. See "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates." These rates are exclusive of other surcharges discussed below.

Certain rate level adjustments for both power and transmission and related rates (referred to herein as the Power Services or Transmission Services "Cost Recovery Adjustment Clause" or "CRAC") and the Financial Reserves Policy Surcharge (the "Financial Reserves Policy Surcharge" or "FRP Surcharge") included in the Final 2024-2025 Rates did not trigger for application to Fiscal Year 2024 power or transmission rate levels. If a Power or Transmission CRAC or FRP Surcharge were to trigger for application to Fiscal Year 2025 power or transmission and related rate levels, Bonneville would notify customers by November 30, 2024. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

In addition to the CRAC and FRP Surcharge mechanisms under the Final 2024-2025 Rates, Bonneville reserves the ability to institute another expedited rate case proceeding and increase rates or rate levels in the rate period, which Bonneville has estimated would take up to six months.

The Final 2024-2025 Rates include the availability of the "Reserves Distribution Clause" or "RDC." A Reserves Distribution Clause is based on RAR level thresholds by business line at September 30 (subject to a *de minimi*s exception described below) and could result in a decision to decrease certain power or transmission rates in either year of the rate period or amounts could be retained by Bonneville for certain purposes. In order to trigger a distribution under the RDC, Power Services' RAR or Transmission Services' RAR must exceed its 120 Days Cash on Hand target ($638 million for Power Services or $233 million for Transmission Services). In addition, from an agency perspective, the total RAR must be at least $653 million, in the aggregate, which is the forecast amount of cash expected to be needed to meet the agency's operating expenses for at least 90 days. The RDC terms include a *de minimis* provision under which Bonneville would not trigger an RDC for implementation for a fiscal year unless the business line RAR were to exceed its 120 Days Cash on Hand target by $5 million.

An RDC has triggered for application to Power Services and Transmission Services Fiscal Year 2024 rates. The Administrator has discretion whether to apply the amount of an RDC distribution to make a downward adjustment to rates or deploy such amounts to other high-value purposes including, but not limited to, debt retirement or capital investments.

On September 30, 2023, Power Services' RAR were $923 million and the total RAR were $1.3 billion, resulting in a Power RDC triggering in the amount of $285 million for application to certain Power Services rate levels in Fiscal Year 2024 (the "Fiscal Year 2023 Power RDC"). The Administrator determined that $165 million of the Fiscal Year 2023 Power RDC would be applied to reduce Power rates from December 2023 through September 2024. Credits are being applied to power customer bills through September 2024. In addition to the rate reduction being applied in Fiscal Year 2024, $90 million of the Fiscal Year 2023 Power RDC amount is being held in Total Financial Reserves for debt reduction in Fiscal Year 2024 (either for early payment of debt or revenue financing of capital expenditures, with any unused amount at the end of Fiscal Year 2024 becoming available to support Bonneville's liquidity or increase the probability of a Power RDC triggering at the end of Fiscal Year 2024), and $30 million is being held in Total Financial Reserves to fund certain fish and wildlife expenses on an accelerated basis (in advance of when such expenditures were originally expected to be made). The Fiscal Year 2023 Power RDC is being challenged in court. See "BONNEVILLE LITIGATION— Fiscal Year 2023 Power RDC Challenge."

On September 30, 2023, Transmission Services' RAR were $363 million and the total RAR were $1.3 billion, resulting in a Transmission RDC triggering in the amount of $130 million for application to certain Transmission Services rate levels in Fiscal Year 2024. The Administrator determined that $50 million of the Transmission RDC would be retained in Total Financial Reserves to fund costs to be incurred in Fiscal Year 2024 above amounts forecast when establishing rates for the current period and $80 million is being held in Total Financial Reserves for debt reduction in Fiscal Year 2024 (either for early payment of debt or revenue financing of capital expenditures, with any unused amount at the end of Fiscal Year 2024 becoming available to support Bonneville's liquidity).

The portions of the Power RDC and Transmission RDC that result in rate reductions being implemented in Fiscal Year 2024, as described above, will have the effect of reducing Bonneville's net revenues in Fiscal Year 2024.

Consistent with longstanding policy, the Final 2024-2025 Rates were prepared to assure payment of all costs and provide at least a 95 percent probability over the two-year rate period that Bonneville will make its scheduled payments to the United States Treasury on time and in full. (Bonneville refers to this probability as "Treasury Payment Probability" or "TPP.") In determining TPP, Bonneville relies on numerous factors including estimates and forecasts of costs, risks and revenues, the ability to increase rate levels on short notice under the CRAC or Financial Reserves Policy Surcharge (hereinafter described), the availability of short-term financial liquidity tools, and RAR. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." Bonneville's United States Treasury payments are payable after Bonneville's non-federal payment obligations such as the lease rental payments for the Project under the Lease-Purchase Agreement. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

For other details related to the Final 2024-2025 Rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Bonneville has begun conducting workshops related to developing rates for power and transmission and related services for Fiscal Year 2026, 2027 and 2028. Bonneville plans to begin the formal rate proceeding in November 2024 and to submit the final rate proposal to FERC by the end of July 2025. In order to align the rate period with expiration of the Long-Term Preference Contracts on September 30, 2028, Bonneville has determined that it will implement a single three-year rate period for Power Services and Transmission Services rates for the next rate period.

Developments Relating to the Endangered Species Act

The operation of the Federal System Hydroelectric Projects by the Corps, Reclamation and Bonneville (also referred to as the "Action Agencies") is subject to the Endangered Species Act ("ESA"). The listing under the ESA of certain anadromous and other native fish species that inhabit the Columbia River and its tributaries has led to the preparation of a series of biological opinions for operation and maintenance of Federal System Hydroelectric Projects on the Columbia and Snake Rivers. Beginning in the early 1990s, the National Oceanic and Atmospheric Administration's National Marine Fisheries Service ("NOAA Fisheries") has issued a succession of biological opinions relating to listed anadromous salmonid species of the Columbia and Snake Rivers. In 2000, the United States of America, Department of Interior, Fish and Wildlife Service ("Fish and Wildlife Service") issued a separate biological opinion regarding ESA-listed bull trout in the Columbia Basin and white sturgeon in the Kootenai River. Because hydropower dam operations in Montana and Idaho affect the listed sturgeon and bull trout as well as the salmonid species covered by the NOAA Fisheries biological opinions, NOAA Fisheries and the Fish and Wildlife Service coordinate their biological opinions regarding hydropower operations. Environmental Impact Statements related to the Federal System Hydroelectric Projects reflect both the NOAA Fisheries' and the Fish and Wildlife Service's biological opinions. Each of the NOAA Fisheries biological opinions from 1993 on has been the subject of litigation and judicial review and has resulted in court orders remanding biological opinions, including NOAA Fisheries' biological opinion for the Columbia and Snake Rivers issued in 2014 (referred to herein as the "2014 Columbia River System Supplemental Biological Opinion"). See "POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

In 2016, the United States District Court for the District of Oregon ("District Court") concluded that the Corps and Reclamation violated the National Environmental Policy Act ("NEPA") and identified a number of deficiencies with the 2014 Columbia River System Supplemental Biological Opinion. The District Court issued an order directing that a new environmental impact statement related to the Columbia River System Operations ("CRSO") be prepared and that a new biological opinion be issued based on findings in the CRSO environmental impact statement to support adoption and implementation of the proposed action consulted upon in the biological opinions. A related case pending in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court") was stayed pending the outcome of the District Court case. For more details related to this case, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

In 2020, the Action Agencies issued a draft CRSO Environmental Impact Statement (the "Draft CRSO EIS") followed by a Final CRSO Environmental Impact Statement (the "Final CRSO EIS") on July 31, 2020. The Final CRSO EIS responded to substantive comments on the Draft CRSO EIS, described the Action Agencies' Preferred Alternative (the "Preferred Alternative"), and included, as appendices, the NOAA Fisheries' biological opinion for the Columbia and Snake Rivers issued in 2020 (referred to herein as the "2020 NOAA Fisheries Columbia River System Biological Opinion") and the Fish and Wildlife Service's biological opinion for the Columbia and Snake Rivers issued in 2020 (referred to herein as the "2020 Fish and Wildlife Service Columbia River System Biological Opinion) (collectively, the "2020 Columbia River System Biological Opinions") that evaluate impacts of the Preferred Alternative. Despite initial estimates in the Draft CRSO EIS of potential upward rate pressure of up to 2.7 percent on power rates when compared to the "No Action Alternative" (which is based on the 2016 system operation rules), subsequent changes in other rate drivers allowed Bonneville to recover its costs while proposing an average power rate decrease in the Final 2022-2023 Rates from the average power rates in effect in the prior period.

Various plaintiffs have filed complaints in the Ninth Circuit Court and District Court challenging the joint record of decision by the Action Agencies adopting the Final CRSO EIS and 2020 Columbia River System Biological Opinions alleging that Action Agencies' decision violated certain provisions of the ESA, NEPA, the Administrative Procedures Act ("APA"), and the Northwest Power Act. Bonneville's part in that record of decision was challenged by three petitioners in the Ninth Circuit Court. These challenges were consolidated on January 13, 2021. There is substantial overlap between the Ninth Circuit Court and District Court cases.

In October 2021, the Biden Administration announced a short-term agreement on the operation of the Federal System Hydroelectric Projects. The agreement paused litigation on the selected alternative in the CRSO EIS Record Of Decision and associated ESA consultations.

As part of mediated discussions related to the CRSO EIS, on September 21, 2023, Bonneville and other agencies and departments within the U.S. Government entered into a memorandum of understanding and settlement agreement with the Confederated Tribes of the Colville Reservation, the Coeur d'Alene Tribe, and the Spokane Tribe of Indians ("P2IP Tribes"). In exchange for a 20 year pause in the CRSO EIS litigation in which the P2IP Tribes challenged the Action Agencies' adoption of the CRSO EIS and associated ESA consultations, Bonneville will make available to the P2IP Tribes a total of $10 million per year from Fiscal Year 2024 – Fiscal Year 2043, adjusted each year for inflation, for a total of $200 million plus adjustments for inflation for implementation of the Phase 2 Implementation Plan ("P2IP") projects for reintroducing specific non-federally protected salmonid stocks above Chief Joseph and Grand Coulee dams in the upper Columbia River Basin.

On October 30, 2023, the remaining parties gave notice they would not seek to revive the litigation through December 15, 2023 to allow for continued mediation discussions. On December 14, 2023 the Biden Administration announced the *U.S. Government Commitments in Support of the Columbia Basin Restoration Initiative and in Partnership with the Six Sovereigns* and associated Memorandum of Understanding (the "December 2023 Agreement"), an agreement to work in partnership with Pacific Northwest Tribes and States to further the restoration of native fish populations, expand Tribally sponsored clean energy production, and provide stability for communities that depend on the Columbia River System. Under the December 2023 Agreement, the Six Sovereigns (the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Nez Perce Tribe, the State of Oregon, and the State of Washington) agreed to a stay of the CRSO EIS litigation in exchange for Bonneville's commitment to make available $200 million over 10 years to the U.S. Fish and Wildlife Service for Lower Snake River Compensation Plan hatchery modernization, upgrades and maintenance; plus an additional $100 million over 10 years for projects that contribute to the restoration of salmon and other native fish populations, as guided by the Six Sovereigns. This agreement concludes the mediation and on February 8, 2024, the U.S. District Court for the District of Oregon granted a stay through December 13, 2028 (with potential for an additional five years), and on February 23, 2024, the U.S. Court of Appeals for the Ninth Circuit dismissed without prejudice litigation regarding the CRSO EIS and associated ESA consultations. The litigation stays are conditioned on the U.S. Government meeting its obligations under the December 2023 Agreement. For a more detailed discussion of the challenges to the 2020 Columbia River System Biological Opinions and Final CRSO EIS, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Costs related to both the P2IP and December 2023 Agreement will be funded through power rates as applied to Bonneville's power customers.

Bonneville's funding commitments are directed at specific actions as described in the P2IP Agreement or the December 2023 Agreement. None of those actions include studies or projects that would further dam breaching. It is the opinion of the General Counsel of Bonneville that breaching or other similar major structural changes at any of the dams of the Federal System would require Congressional enactment authorizing such action.

In August 2021, the plaintiffs requested settlement discussions regarding short-term fish passage operations for 2022. Based on the settlement reached by the parties regarding spill for the 2022 fish passage season (approximately April-June 2022) at eight federal Columbia River System dams, both cases were stayed through July 2022. The litigation stay was extended until August 31, 2023, at the District Court and until September 8, 2023 in the Ninth Circuit Court. Under the December 2023 Agreement, the spill for the 2024 fish passage season (approximately April-June 2024) at the Snake River and Columbia River Federal System dams is similar to the effects of the spill for the 2022 and 2023 fish passage season. For a more detailed discussion of the challenges to the 2020 Columbia River System Biological Opinions and Final CRSO EIS, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

There are three petitions currently filed with the Ninth Circuit Court challenging Bonneville's authority under the Northwest Power Act to sign on to the December 2023 Agreement. Bonneville is unable to predict the outcome of this litigation or its potential impact on the December 2023 Agreement and associated spill operations.

2024-2028 Strategic Plan

In August 2023, Bonneville published its updated five-year strategic plan for calendar years 2024 through 2028 (the "2024-2028 Strategic Plan"). Building on the success of the 2018-2023 Strategic Plan, the 2024-2028 Strategic Plan recognizes the need to pivot in certain areas to help the Northwest thrive in this era of transformation while laying the framework for Bonneville to remain competitive as it enhances reliability, responds to changing customer needs, and strengthens resilience in the changing electric utility industry landscape. The 2024-2028 Strategic Plan sets forth the following six strategic goals that Bonneville expects will be its central reference point over the next five years: (i) Invest in people; (ii) Enhance the value of products and services; (iii) Sustain financial strength (iv) Mature asset management; (v) Preserve safe and reliable system operations; and (vi) Modernize business systems and processes. Bonneville will also continue its long-standing commitment to environmental stewardship by protecting local natural resources, enhancing conditions for fish and wildlife and other mitigation efforts. For additional details regarding the 2024-2028 Strategic Plan, see "BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville Financial Operations."

POWER SERVICES

Bonneville's Power Services is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. Power Services was responsible for approximately $3.2 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 73 percent, of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2023.

Description of the Generation Resources of the Federal System

Generation

Bonneville has statutory obligations to meet certain electric power loads placed on it by certain Regional customers. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." To meet these loads, Bonneville relies on an array of power resources and power purchases, which, together with the Federal Transmission System and certain other features, constitute the Federal System. The Federal System includes those portions of the federal investment in the Federal System Hydroelectric Projects that have been allocated by federal law or policy to power generation for repayment. The Federal System also includes power from non-federally-owned generating resources, including but not limited to the Columbia Generating Station, and contract purchases from and other arrangements with power suppliers.

Bonneville defines "firm power" as electric power that is continuously available from the Federal System during adverse water conditions to meet Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on assumptions related to the tenth percentile of the Federal System output result for the Columbia River basin referred to herein as "Low Water Flows" (and is frequently referred to by Bonneville as "Firm Water"). Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity (measured in megawatts) and firm energy (measured in annual average megawatts). Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2025 (August 1, 2024 through July 31, 2025), the total Federal System would be capable of producing approximately 7,962 annual average megawatts of firm energy under Firm Water conditions and not accounting for transmission line losses. This generation includes approximately 6,708 annual average megawatts from Reclamation and Corps hydro projects, approximately 994 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including hydropower and renewable generation projects), and approximately 227 annual average megawatts of firm energy from power purchases, exchanges, and other non-federal transactions. See the table entitled "Operating Federal System Projects for Operating Year 2025."

Analyses as of May 23, 2024, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2024 water supply for the Columbia River basin will be approximately 80 percent of the 30-year historical average, as measured in terms of millions of acre feet of water (or "MAF") runoff at The Dalles Dam. Runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation.

Federal Hydro-Generation

The share of hydropower from the Federal System Hydroelectric Projects and a small amount of power Bonneville has acquired from non-federally-owned hydroelectric projects for Operating Year 2025 is estimated to be approximately 87 percent of Bonneville's total firm power supply under Firm Water. See the table entitled "Operating Federal System Projects for Operating Year 2025." Bonneville's large resource base of hydropower results in operating and planning characteristics that differ from those of major utilities that lack a substantial hydropower base.

The Federal System as primarily a hydropower system, with access to substantial reservoir storage, has peaking capacity that exceeds the Federal System peaking loads and power reserve requirements, in most months, and in most water years. Bonneville estimates that, in most months of an operating year and under most water and load conditions, its peaking capacity for long-term planning purposes will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because, as Bonneville acquires new resources or augments the Federal System with energy purchases (or similar actions) in order to balance annual and seasonal firm energy needs, these additions contribute more peaking capacity.

At this time, Bonneville's resource planning focuses primarily on the need to acquire sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal, gas, oil, and nuclear based generating systems must also focus their resource planning and acquisition on having enough peaking capacity to meet peak loads. As additional non-power requirements are placed on the Federal System hydroelectric operations and as Bonneville's peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity from resources or purchases to meet peak load obligations. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies."

In general, for long-term planning purposes Bonneville estimates the amount of electric power it will need in order to meet loads above the expected Federal System firm power generated under Low Water Flows/Firm Water. Firm energy from hydro reflects generation under assumptions of low streamflow derived from Regional streamflow records. Thus, the fuel supply (streamflow) and generating capability for firm energy from hydro have a high probability of occurring from year to year.

For ratemaking and financial planning purposes, however, Bonneville takes into account the amount of electric power it expects to have available to market based on water conditions that reflect average circumstances. The amount of seasonal surplus energy generated by the Federal System that is above the amount needed to meet Bonneville's Regional loads depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2025, the Federal System is forecast to generate seasonal surplus energy of 1,089 annual average megawatts, assuming median water conditions (50th percentile). In years with high water conditions (90th percentile) the amount of seasonal surplus energy could be as much as 3,020 annual average megawatts. In years with Low Water Flows/Firm Water, the amount of seasonal surplus energy generated by the Federal System could be quite small or not available at all.

Notwithstanding that the amount and timing of seasonal surplus energy is subject to variability, Bonneville markets almost all seasonal surplus energy on a contractual basis under which the commitment to provide energy is firm.

The Corps and Reclamation operate the Federal System Hydroelectric Projects to serve multiple statutory purposes. These purposes include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection, as well as power generation. Non-power purposes have placed requirements on operation of the reservoirs and have thereby limited hydropower production. Bonneville takes into account the non-power requirements and other factors in assessing the marketable power from these projects.

These requirements change the shape, availability, and timeliness of federal hydropower to meet load. The information in the “Operating Federal System Projects for Operating Year 2025” table estimates the operation of the Federal System under the Pacific Northwest Coordination Agreement (“PNCA”). The PNCA defines the planning and operation of Bonneville, Pacific Northwest utilities, and other parties with generating facilities within the Region’s hydroelectric system. The hydro-regulation study incorporated measures, including but not limited to those: (i) in furtherance of the ESA as set forth by the NOAA Fisheries in biological opinions relating to the operation of the Federal System dams on the Columbia River and Snake River and tributaries and under related court-ordered operations, (ii) in furtherance of the ESA as set forth by the Fish and Wildlife Service in biological opinions relating to operation of certain Federal System dams on the Snake River, Columbia River, and tributaries, and (iii) operations described in the Northwest Power and Conservation Council’s Fish and Wildlife Program (“Council’s Fish and Wildlife Program”). These measures include flow augmentation for juvenile fish migration in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the lower Snake and Columbia River dams to provide for non-turbine passage routes for juvenile fish migrants, and additional flows for Kootenai River white sturgeon in the spring. As new biological opinions and similar non-power requirements are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in estimates of the availability of federal hydropower under all water conditions. See “—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The Endangered Species Act.”

Other Power Resources and Contract Purchases

The balance of the Federal System electric power resources, apart from the hydropower generating resources, includes power from the Columbia Generating Station, which has the largest capacity for energy production of the non-federal resources included in the Federal System. See Footnote 10 in the “Operating Federal System Projects for Operating Year 2025” table. In addition, Bonneville has a number of power purchase and related contracts under which Bonneville receives electric power and which are not tied to specific generating resources (“Other Federal Contracts”). Bonneville projects that it will continue to have long-term contracts for power purchases, power or energy exchanges, power purchased or assigned under the Columbia River Treaty, transmission loss returns under the “Slice” contracts (as described below, under Slice service, Bonneville commits to provide a Slice product under which the purchaser receives a proportionate share of the actual output of the Federal System as generated) and similar non-federal transactions. In aggregate these arrangements will provide approximately 227 annual average megawatts of firm energy in Operating Year 2025. See Footnote 12 in the following table “Operating Federal System Projects for Operating Year 2025.”

Operating Federal System Projects for Operating Year 2025

In all years, the energy generating capability of the Federal System Hydroelectric Projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, streamflow requirements pursuant to biological opinions, and other operating limitations. As part of Bonneville’s latest Climate Change Resiliency effort, Bonneville determined that utilizing the last 30-years of the 90–year historical streamflow record (the 2020 Modified Streamflows) provided the most accurate reflection of expected future streamflows by capturing the impacts of climate change that are occurring during that timeframe. As a result, Bonneville is now utilizing the latest 30 years of streamflows in its planning studies. During this period, Bonneville estimates the energy generating capability of Federal System Hydroelectric Projects in any given operating year by assuming that these historical water conditions reflect what will occur in that specific operating year and making adjustments in the expected generating capability to reflect the current physical capacity operating limitations and current streamflow requirements. Energy generation estimates are further refined to reflect factors unique to the subject operating year such as initial storage reservoir conditions.

The following table shows, for Operating Year 2025, the Federal System Maximum Capacity and energy capability using (i) Low Water Flows at the 10th percentile (referred to as “Firm Energy”), (ii) median water conditions at the 50th percentile (referred to as “Median Energy”), and (iii) high water conditions at the 90th percentile (referred to as “High Energy”). The same forecasting procedures are also used for non-federally-owned hydroelectric projects. Thermal projects, the output of which does not vary with river flow conditions, are estimated using current generating capacity, plant capacity factors, and maintenance schedules. See “POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The Endangered Species Act” and “BONNEVILLE LITIGATION—Columbia River ESA Litigation.”

Operating Federal System Projects for Operating Year 2025(1)

Project	Initial Service Year	Number of Units	Maximum Capacity (MW)(2)	High Energy (aMW)(3)	Median Energy (aMW)(4)	Firm Energy (aMW)(5)
United States Bureau of Reclamation (Reclamation) Hydro Projects						
Grand Coulee including Pump Turbine	1941	33	6,684	2,991	2,362	1,958
Hungry Horse	1952	4	310	147	89	91
Other Reclamation Projects(6)		19	300	193	154	140
1. Total Reclamation Projects		56	7,294	3,331	2,605	2,189
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,614	1,702	1,393	1,144
John Day	1968	16	2,480	1,339	984	760
The Dalles w/o Fishway(7)	1957	22	2,080	1,038	810	626
Bonneville	1938	18	1,221	672	547	386
McNary	1953	14	1,120	651	562	458
Lower Granite	1975	6	930	325	194	128
Lower Monumental	1969	6	930	348	212	141
Little Goose	1970	6	930	318	181	146
Ice Harbor	1961	6	693	299	187	149
Libby	1975	5	605	253	234	201
Dworshak	1974	3	465	311	196	149
Other Corps Projects(8)		20	574	245	265	200
2. Total Corps Projects		149	14,642	7,501	5,765	4,488
3. Total Reclamation and Corps Projects (line 1 + line 2)		**205**	**21,936**	**10,832**	**8,370**	**6,677**
Non-Federally-Owned Projects						
Other Non-Federal Hydro Projects(9)		4	77	35	31	31
Columbia Generating Station(10)	1984	1	1,178	994	994	994
Other Non-Federal Projects(11)		7	-	33	33	33
4. Total Non-Federally-Owned Projects		**12**	**1,255**	**1,062**	**1,058**	**1,058**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(12)		**n/a**	**448**	**242**	**232**	**227**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**217**	**23,639**	**12,136**	**9,660**	**7,962**

Source: 2023 Pacific Northwest Loads and Resources Study, Bonneville, April 20, 2023.

(1) Operating Year 2025 is August 1, 2024 through July 31, 2025. Any discrepancies in totals for figures portrayed in this table and the 2023 Pacific Northwest Loads and Resources Study are due to rounding.

(2) Maximum Capacity represents full capacity of resources including overload.

(3) High Energy capability is the estimated amount of hydroelectric energy to be produced using high water conditions at the 90th percentile for energy in annual average megawatts ("aMW"). Bonneville's hydro-regulation study incorporates spill assumptions similar to the Selected Alternative published in the 2020 Columbia River System Biological Opinion for the Snake River and Columbia River dams. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act" and "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

(4) Median Energy capability is the estimated amount of hydro energy to be produced using median water conditions at the 50th percentile for energy, in aMW.

(5) Firm Energy capability is the estimated amount of hydro energy to be produced using Low water Flows at the tenth percentile for energy, in aMW.

(6) Other Reclamation Projects include: Anderson Ranch (1950), Black Canyon (1925), Boise Diversion (1908), Chandler (1956), Green Springs (1960), Minidoka (1909), Palisades (1957), and Roza (1958).

(7) The Dalles Dam complex also includes two units that generate energy in connection with a fishway at the dam. They produce approximately five megawatts of both peak capacity and energy. Bonneville does not receive the output of the fishway project and it is not included in this table.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954), and Lost Creek (1975). Some of these projects have less January capacity than annual energy due to the fact that they do not operate in January.

(9) Other Non-Federal Hydro Projects include project capability from the following hydroelectric projects estimated by water conditions: Lewis County PUD's Cowlitz Falls Project (1994), the State of Idaho Department of Water Resources' Clearwater Hydro (1998), Dworshak Small Hydro (2000), and Rocky Brook Hydro (1999). Bonneville has acquired the output from the Cowlitz Falls Project through June 30, 2032. If Bonneville's contracts to purchase power from any of these projects change or are renewed, those changes will be reflected in future studies.

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station is expected to provide approximately 994 aMW in most refueling years and 1,116 aMW in non-refueling years. Columbia Generating Station is scheduled for refueling in Operating Year 2025 and, therefore, is expected to provide approximately 994 aMW in such operating year. This amount does not take into account any reductions in generation requested by Bonneville related to oversupply events. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Renewable Generation Development and Integration into the Federal Transmission System."

(11) Other Non-Federal Projects include project output from the following projects: a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project and a share from NWW Wind Power's Klondike Phase III (2007).

(12) Federal Contract Purchases include contracts for power purchases, exchanges, and other non-federal transactions with entities (including from non-federal hydro projects) from both inside and outside the Region and from Canada. This also includes amounts of power returned from Slice customers for transmission line losses.

Bonneville's Power Trading Floor Activities

Much of Bonneville's generation resource base is provided by hydroelectric facilities, the output of which is affected by weather conditions, streamflow, operating constraints, and other factors. In most years, Bonneville sells substantial amounts of seasonal surplus energy in market-based transactions. In addition, other generation conditions and operational requirements may affect generation output. Thus, actual surplus generation will vary hourly, daily, monthly, or seasonally. In addition, power loads fluctuate based on consumer usage, demands to maintain transmission system stability, and other factors. Loads and the availability of generation from Bonneville's own resources can vary substantially and actual power from Bonneville's own generating resources may not match its loads. When

Bonneville's loads exceed its generation capabilities, Bonneville buys energy in market-based transactions. In the near-term (prior to and during a fiscal year), Bonneville routinely produces probabilistic and discrete energy inventory studies estimating potential surplus or deficits for specific future time periods. Based on these studies and specific marketing guidelines, Bonneville actively manages short-term surpluses and deficits through hourly, within-month, and forward transactions of physical power, futures, and power put and call options.

Bonneville believes that its revenues and expenses from market transactions are, and will be, subject to several key risks: (i) the availability of electric power supplies generally (including, among other sources, electricity supplied by natural-gas fired generators, wind generators, and other non-Federal System hydroelectric generators), (ii) the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from sales of surplus energy and capacity and the cost of necessary power purchases Bonneville may have to make to meet contracted loads and hydraulic objectives, (iii) the level of Bonneville's load serving obligation, (iv) water conditions in the Columbia River basin, which determine the amount of hydroelectric power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments, (v) changes in fish protection requirements, which could be the source of substantial additional expense to Bonneville and could further affect the amount and value of hydroelectric power from the Federal System, (vi) continued availability of existing Federal System generating resources, (vii) transmission availability influenced by planned maintenance and unplanned outages or de-rates associated with extreme weather events, and (viii) operating costs, generally.

Bonneville has put in place risk management procedures, standards, and policies that it believes adequately mitigate risk from these activities. Nonetheless, Bonneville's exposure to operational variability means that Bonneville may in certain conditions have to incur substantial purchased power expense. See "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

Regional Customers and Other Power Contract Parties of Bonneville's Power Services

Bonneville's primary firm power customers are composed of several principal groups: Preference Customers, DSIs, Federal Agencies and Regional IOUs. Bonneville enters into contracts to sell surplus power with parties ("Market Counterparties"), which are commercial power-related arrangements that are not derived or originally derived from Bonneville's statutory firm power obligations. See "—Market Counterparties and Exports of Surplus Power to the Pacific Southwest." Under the Northwest Power Act, Bonneville has a statutory obligation to meet electric power loads in the Region that are placed on Bonneville by electric power utilities. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region."

Preference Customers

Bonneville's primary customer base is composed of Preference Customers, which make long-term power purchases from Bonneville at cost-based rates to meet their native loads in the Region. Preference Customers are qualifying publicly-owned utilities, consumer-owned electric cooperatives, and tribal utilities within the Region, and they are entitled by law to a preference and priority ("Public Preference") in the purchase of available Federal System power for their load requirements in the Region. Such customers are eligible to purchase firm power at Bonneville's lowest cost rate, the PF Preference Rate, for most of their loads. Under Public Preference, Bonneville must first meet a Preference Customer's request for available Federal System power over a competing request from a non-Preference Customer. In the opinion of Bonneville's General Counsel, Public Preference does not compel Bonneville to lower the offered price of surplus power to Preference Customers before meeting a competing request at a higher price for such power from a non-Preference Customer. Bonneville sells power to certain large Preference Customers under market-type contracts other than for their own load requirements.

For Operating Year 2025, Bonneville forecasts that it will meet approximately 6,942 annual average megawatts of Preference Customer loads.

Direct Service Industrial Customers

Bonneville may sell, but is not required by federal law to sell, power to a limited number of DSIs within the Region for their direct consumption. Historically, Bonneville's service to DSIs was to supply power to serve aluminum smelting or processing facilities. Such entities and load are no longer supplied by Bonneville under any power sales contracts since they have ceased to operate. Currently, Bonneville has one long-term contract to sell power at the IP Rate directly to one DSI—Port Townsend Paper Company—in an aggregate amount of up to 11 annual average megawatts.

Reclamation and Other Federal Agency Customers

Bonneville is required by federal law to provide firm power to Reclamation for certain irrigation pumping stations. For Operating Year 2025, Bonneville forecasts that it will meet approximately 188 annual average megawatts of Reclamation loads. Bonneville is not required by federal law to meet the loads of other federal agencies but has long-term contracts to do so. For Operating Year 2025, Bonneville forecasts that it will meet approximately 148 annual average megawatts of the loads of federal agencies other than Reclamation. While Reclamation and the other federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at PF Preference Rates.

Regional Investor-Owned Utilities

As required by the Northwest Power Act, Bonneville has offered, and four of the six Regional IOUs have agreed to, contracts under which Bonneville could serve Regional IOUs with electric power for their net requirements (meaning a Regional IOU's load in the Region that is not met by the Regional IOU with its own designated power supplies) beginning in Fiscal Year 2020 if such service was requested not later than the end of Fiscal Year 2016. Although none of the Regional IOUs made an election to purchase requirements power for Fiscal Years 2020 through 2028, thereby providing Bonneville with advance notice that there is no need to add resources or take other steps to meet these loads, Bonneville could still be required to serve any Regional IOU with electric power for their net requirements for Fiscal Years 2020 through 2028 if a Regional IOU were to request that Bonneville waive its contractual notice requirement. Any requirements power provided by Bonneville under these contracts would be priced at the New Resources Rate ("NR Rate"). This rate would in effect reflect Bonneville's marginal cost of resources used to supply such IOU load amount.

Bonneville believes that it is unlikely, unless circumstances change, that Regional IOUs will place substantial loads, if any, on Bonneville under the Regional IOU long-term requirements contracts because (i) there is no reason to expect that Bonneville's cost to meet such loads, as reflected in the NR Rate, would be significantly lower than the Regional IOUs' cost to meet such loads, (ii) the Regional IOUs are financially motivated to make investments in new generating facilities in order to obtain shareholder returns, (iii) most of the Regional IOUs have state-mandated renewable resource purchase obligations and would have to be assured that such obligations are addressed in any power purchases from Bonneville, and (iv) the NR Rate bears additional costs of statutory rate protection afforded to Preference Customers, thereby likely making the rate less economic compared to market alternatives.

Bonneville provides power to the Regional IOUs under contracts other than long-term firm requirements contracts. Bonneville also sells substantial amounts of peaking capacity to Regional IOUs. Power sales to Regional IOUs are distinct from Bonneville's contracts implementing the Residential Exchange Program, as provided by statute. The Residential Exchange Program obligations, described herein, result in payments by Bonneville to participating utilities. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

Bonneville has a large number of parties with which it has commercial power-related arrangements that are not based on Bonneville's statutory obligations (as in the case of statutory load-meeting obligations to Preference Customers and Regional IOUs, and payment obligations under the Residential Exchange Program) or on long-term relationships that are based on prior statutory obligations (as in the case of DSIs). These counterparties include utilities located outside the Region, power marketers, and independent power producers. Transactions with these counterparties include, but are not limited to, arrangements for purchases of power, surplus power sales and/or exchanges of transmission, and related services. Of the foregoing contracts, those that involve long-term commitments are referred to by Bonneville in its loads and resources forecasts as "Other Contract Deliveries." The commitments include power deliveries to entities outside the Region ("Exports") and to entities within the Region ("Intra-Regional Transfers (Out)"). The terms of these deliveries are specified by individual provisions and have various delivery arrangements and rate structures and Bonneville assumes in its load forecasts that such loads will be served by Federal System firm resources regardless of weather, water, or economic conditions. For Operating Year 2025, Bonneville forecasts that Other Contract Deliveries will be approximately 707 annual average megawatts.

Bonneville sells surplus power via the Pacific Northwest-Pacific Southwest Intertie (the "Southern Intertie") transmission lines to Pacific Southwest utilities, power marketers, the California Independent System Operator ("Cal-ISO"), and other entities, which use most of such power to serve California loads. These sales are composed of surplus firm power and seasonal surplus energy that is not needed to meet Bonneville's Regional energy requirements. Sales of Bonneville power for use outside the Pacific Northwest are subject to a statutory requirement that Bonneville offer such power for sale to Regional utilities before offering such power to a customer outside the Region. Any Regional customer that elects to step in front of a proposed extra-regional sale must accept the same terms, conditions, and price offered.

In addition, Bonneville's contracts for firm energy and peaking capacity sales outside the Region include, as required by the Regional Preference Act, recall provisions that enable Bonneville to withhold delivery of such power, upon advance notice, if needed to meet the energy requirements of Bonneville's Regional customers. With certain limited exceptions, Bonneville's sales of Federal System power out of the Region are subject to termination on 60 days' notice in the case of energy and on 60 months' notice in the case of peaking capacity. These rights help Bonneville assure that the power needs of its Regional customers are met. Power exchange contracts are not required to contain the Regional recall provisions.

Pacific Southwest utilities typically account for a large share of Bonneville's sales of seasonal surplus energy. These transactions account for a large share of revenues from Bonneville's Regional exports. The amount of seasonal surplus energy that Bonneville has available to sell depends on precipitation and other power supply factors in the Northwest, the available transmission capacity of the Southern Intertie, the attributes of power markets across the Western Electricity Coordination Council ("WECC"), and other factors that may constrain exports notwithstanding the availability of power.

While Bonneville designs its power rates to recover its costs, it does so with an expectation that some revenue will be the result of surplus power sales at competitive pricing terms in the wholesale electricity marketplace. Revenues that Bonneville obtains from these surplus sales depend on market conditions and the resulting prices. These revenues are affected by the weather and other factors that affect demand in the Pacific Northwest and Southwest, and the cost and availability of alternatives to Bonneville's power. The value of such surplus power sales is frequently dependent on other electric energy suppliers' resource costs such as the cost of hydropower or coal-, oil- and natural gas-fired generation. Bonneville believes that if its power sales in the Region were to decline, any resulting surplus of power could be exported outside the Pacific Northwest. Such sales may be limited, however, by transmission capacity and other factors.

Credit Risk

Credit risk may be concentrated to the extent that one or more groups of counterparties, including purchasers and sellers, in power transactions with Bonneville have similar economic, industry, or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. Credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to the circumstances that relate to other market participants that have a direct or indirect relationship with such a counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. Despite mitigation efforts, however, defaults by counterparties occur from time to time. To date, no such default has had a material adverse effect on Bonneville. Bonneville continues to actively monitor the creditworthiness of counterparties with whom it executes wholesale energy transactions and uses a variety of risk mitigation techniques to limit its exposure where it believes appropriate.

Power Services' Largest Customers

The following table lists Power Services' top ten largest customers in terms of their percentage contribution to Power Services' overall sales revenue in Fiscal Year 2023.

Bonneville Power Services' Ten Largest Customers By Sales[(1)]
(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2023)

Customer Name	Approximate % of Sales
Snohomish County PUD No 1 (Preference Customer)	8%
Pacific Northwest Generating Cooperative[(2)] (Preference Customer)	6%
Portland General Electric Company (Regional IOU)	6%
Cowlitz County PUD No 1 (Preference Customer)	5%
City of Seattle, City Light Dept. (Preference Customer)	4%
Tacoma Power (Preference Customer)	4%
Clark Public Utilities (Preference Customer)	3%
Eugene Water & Electric Board (Preference Customer)	3%
Shell Energy North America (U.S.) LP (Power Marketer)	3%
Transalta Energy Marketing (U.S.) Inc. (Power Marketer)	3%

(1) Excludes inter-business line transactions between Power Services and Transmission Services. Transmission Services obtains electric power from Power Services to enable Transmission Services to provide transmission related products, particularly ancillary services.

(2) The Pacific Northwest Generating Cooperative is a joint operating agency that buys federal power from Bonneville on behalf of 15 electric cooperatives—each a Preference Customer—to supply their aggregated load demand.

Certain Statutes and Other Matters Affecting Bonneville's Power Services

Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region

The Northwest Power Act requires Bonneville to meet certain firm loads in the Region placed on Bonneville by contract by various Preference Customers and Regional IOUs. Bonneville believes it does not have a statutory obligation to meet all firm loads within the Region.

Under the Northwest Power Act, when requested, Bonneville must offer a contract for the sale of firm power to each eligible utility, which includes Preference Customers and Regional IOUs, to meet that portion of the utility's Regional firm power loads net of the non-federal resources used by the customer to supply its load. The extent of Bonneville's obligation to meet the firm loads of a requesting utility is determined by the amount by which the utility's firm power loads exceed (i) the capability of the utility's firm peaking capacity and energy resources used in Operating Year 1979 to serve its own loads, and (ii) such other resources as the utility determines, pursuant to its power sales contract with Bonneville, will be used to serve the utility's firm loads in the Region. Bonneville refers to this as its "net requirements" obligation. If Bonneville has or expects to have inadequate power and reasonably determines it cannot acquire resources to meet all of its contractual obligations to its customers, certain statutory and contractual provisions allow for the allocation of available power.

As required by law, Bonneville's power sales contracts with Regional utilities contain provisions that require prior notice by the utility before it may use, or discontinue using, a generating resource to serve such utility's own firm loads in the Region. The amount of notice required depends on whether Bonneville has a firm power surplus and whether the Regional utility's generating resource is being added to serve or withdrawn from serving the utility's own firm load. These provisions are designed to give Bonneville advance notice of the need to obtain additional resources or take other steps to meet such load.

Some of Bonneville's Preference Customers have generating resources, which they may use to meet their firm loads in the Region. Each of such customers has to identify the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are included in Bonneville's currently effective Long-Term Preference Contracts. The Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load ("Tier 2 Loads") on Bonneville above a baseline level of loads ("Tier 1 Loads") reflective of loads placed on Bonneville prior to the commencement of power sales under Long-Term Preference Contracts.

Bonneville is also directed by federal law to provide electric power from the Federal System to Reclamation to operate 13 separate water pumping projects. See "—Regional Customers and Other Power Contract Parties of Bonneville's Power Services—Reclamation and Other Federal Agency Customers."

Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products. Bonneville currently provides three primary types of power service under the Long-Term Preference Contracts and its sales agreements with federal agencies: (i) Load Following service, (ii) Block service, and (iii) Slice/Block service, which is an integrated power product combining Slice of the System (or "Slice") and Block power. Under Load Following service, Bonneville provides the actual power requirements of the related customer (this is also known as "Full Requirements" product). Under Block service, the customer receives planned or fixed amounts of power at designated times. Under Slice/Block service, Bonneville commits to provide a Slice product under which the purchaser receives a proportionate share of the actual output of the Federal System as generated, and a "Block" product under which the customer receives fixed amounts of power at designated times.

Over 125 Preference Customers and all of Bonneville's seven federal agency customers purchase Load Following service and for Operating Year 2025 Bonneville forecasts that these loads will be approximately 3,886 annual average megawatts. By contrast, 10 separate Preference Customers purchase on a Slice/Block basis. For Operating Year 2025, Bonneville forecasts that its Slice/Block loads will be approximately 2,672 annual average megawatts in total, approximately half of which is expected to be for the Block portion and approximately half of which is expected to be for the Slice portion.

For reference, the Slice portion of Slice/Block service currently represents approximately 20 percent of a contractually-established measure of the output of the Federal System Hydroelectric Projects, the Columbia Generating Station, certain other non-federally-owned generation projects, and the electric power available to Bonneville after netting receipts and deliveries of power under certain long-term power transactions. The foregoing load forecasts reflect an attempt to predict actual loads that will be met under the specified type of service, which loads vary with weather, economic and other conditions.

Bonneville provides all of the foregoing power products at PF Preference Rates, although the particular rate features, levels and determinants vary depending on the power product. All of the Long-Term Preference Contracts and the federal agency power sales subject the customers to a payment commitment under which they are required to pay for power that is tendered by Bonneville in conformity with the applicable power sales contract. For Slice, the customers pay a fixed percentage of the costs of the Federal System generation without regard to the amount of power actually generated. In either case, if a customer's net requirements decline, the customer's purchase obligation from Bonneville is reduced commensurately. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their net requirements. If their net requirements decline, the Block portion is reduced first.

Tiered Rates for Long-Term Preference Contracts. Prior to Fiscal Year 2012, when Bonneville augmented Federal System resources with long-term power purchases or other generating resources, the costs of these typically more expensive purchases were, in general, melded with the Federal System's low, embedded-cost power, creating integrated power rates that masked both the real value of then-existing Federal System power and the incremental costs of meeting load growth. This cost-melding effect created incentives for Preference Customers to place incremental load growth on Bonneville and exposed Bonneville to certain associated risks relating to obtaining electric power to meet the incremental loads. Under the Long-Term Preference Contracts, Bonneville sells at PF Preference Rates that are "tiered" so that power that Bonneville sells to meet the incremental Preference Customer loads above a baseline level of loads is provided at rates that directly and exclusively recover the associated costs that Bonneville incurs in meeting such incremental loads. The Long-Term Preference Contracts involve two tiers of power rates, which Bonneville expects to establish biennially in all but the final three years of Long-Term Preference Contracts: "Tier 1 PF Rates" and "Tier 2 PF Rates."

Tier 1 PF Loads and Tier 1 PF Rates. Preference Customers (and federal agencies) purchase a limited amount of power at Tier 1 PF Rates, which rates in general reflect the historically embedded costs of power from the Federal System. A customer's right to purchase power at Tier 1 PF Rates is capped in general at an amount equal to the net requirement loads it placed on Bonneville in Operating Year 2010 (with certain possible adjustments) ("Tier 1 Loads"), thus, the aggregate amount of power that can be purchased at Tier 1 PF Rates in general reflects the generating output of the Federal System in Fiscal Year 2010 (updated with each rate period to reflect changed Federal System generation expectations). The aggregate amount of power loads served at Tier 1 PF Rates in Fiscal Year 2023 was 6,518 annual average megawatts. The aggregate amount of power loads to be served at Tier 1 PF Rates has been estimated at 6,972 annual average megawatts for Fiscal Year 2024 and 7,022 annual average megawatts for Fiscal Year 2025.

If and to the extent that the existing Federal System resources (including the Columbia Generating Station) whose costs are allocated for recovery in Tier 1 PF Rates were to decline in capability, Tier 1 PF Rates would nonetheless continue to recover the costs of the related resources. The amount of power that Bonneville would be obligated to sell at Tier 1 PF Rates would also decline commensurate with the reduction in resource capability, although the reduction in obligation to sell at Tier 1 PF Rates would not occur until the rate period following the rate period in which the resource capability reduction occurred.

The aggregate amount of power available to be purchased at Tier 1 PF Rates may also be expanded in certain limited circumstances: (i) up to 70 annual average megawatts to serve an increase in DOE load, and (ii) up to 250 annual average megawatts in aggregate, if necessary, for new Preference Customers and load growth of certain tribal utility customers. From time to time, Bonneville receives inquiries from interested parties about becoming new Preference Customers. Bonneville is unable to predict whether additional new Preference Customers will form or the amount of power, if any, they will purchase from Bonneville at Tier 1 PF Rates.

Bonneville follows a "Tiered Rates Methodology" in each rate proceeding to allocate costs and set the respective Tier 1 PF Rates and Tier 2 PF Rates. Costs that are and will be allocated to Tier 1 PF Rates include but are not limited to: the costs assigned to power rates for the Net Billed Projects (some Net Billed Project debt service costs are assigned to be recovered in Transmission Services rates), Federal System fish and wildlife costs, electric power conservation programs, power benefits (if any) to be provided to DSIs, and Residential Exchange Program benefits. Under the Tiered Rates Methodology, most of the benefits of seasonal surplus energy from the Federal System are provided to Preference Customers in Tier 1 PF Rates. In the case of Slice, those customers receive a proportionate share of Federal System seasonal surplus energy to use for native loads (or to market in the case of a small portion of Slice which is a non-requirements product). The revenue benefits that Bonneville receives from its own marketing of seasonal surplus energy are allocated to non-Slice Tier 1 PF Rates (primarily, to rates for Block and Load Following power products).

Tier 2 PF Rates and Tier 2 Loads. In contrast to Tier 1 Loads, "Tier 2 Loads" are loads that a customer places on Bonneville that are incremental to the customer's right to purchase at Tier 1 PF Rates. Under the Tiered Rates Methodology, Tier 2 PF Rates recover only the cost to Bonneville of meeting Tier 2 Loads for Preference Customers that elect to purchase power from Bonneville to meet Tier 2 Loads. Such purchases are integrated with purchases of power for Tier 1 Loads into a single power purchase, although the purchase of power from Bonneville for Tier 2 Loads is made on a take-or-pay basis for the specified amount of power.

Bonneville provides several approaches for Preference Customers to define the extent, if any, to which Bonneville will meet their Tier 2 Loads. Bonneville provides the customers the ability to rely entirely on Bonneville to meet all such loads throughout the entire term of the contracts. Bonneville also allows the customers to rely on Bonneville, with specified notice to Bonneville, to meet all or a portion of their Tier 2 Loads for defined multi-year periods through the term of the agreements. Under this approach, a participating Preference Customer may require Bonneville to meet none, all, or designated portions of the customer's Tier 2 Loads. In addition, Bonneville allows customers to make all or portions of their Tier 2 purchases from specified resources or resource pools obtained by Bonneville. This is expected to assist such customers in meeting renewable resource or other requirements or goals.

Bonneville is obligated to meet approximately 211 annual average megawatts of Tier 2 Loads in Fiscal Year 2024 and approximately 402 annual average megawatts in Fiscal Year 2025. Tier 2 Loads were 63 annual average megawatts in Fiscal Year 2021, 157 annual average megawatts in Fiscal Year 2022, and 173 annual average megawatts in Fiscal Year 2023. As required under the Long-Term Preference Contracts, those customers requesting that Bonneville meet their Tier 2 Loads through Fiscal Year 2028 have made their elections. However, the aggregate amount of Tier 2 Loads that Bonneville will be obligated to meet in Fiscal Year 2026, Fiscal Year 2027, and Fiscal Year 2028 will not be finally determined until the rate case for that period.

Comparison of Tier 1 PF Rates and Tier 2 PF Rates. When developing the Tiered Rate Methodology, Bonneville expected that Tier 1 PF Rates would typically be lower than Tier 2 PF Rates because the embedded cost structure for power from the existing Federal System (in general, as of the time of the commencement of power sales under the Long-Term Preference Contracts, which costs are and will be allocated for recovery in Tier 1 PF Rates) would likely be lower than the cost of new resources obtained to meet Tier 2 Loads and allocated for recovery in Tier 2 PF Rates. However, given low market prices for electric power in Fiscal Year 2020 through Fiscal Year 2023, Tier 2 PF Rates were lower than Tier 1 PF Rates during that period. During the 2020-2021 Rate Period, average Tier 2 PF Rates were approximately $31.76 per megawatt hour and average Tier 1 PF Rates were approximately $35.62 per megawatt hour (exclusive of any rate adjustment mechanisms). Under the Final 2022-2023 Rates, average Tier 2 PF Rates were approximately $33.65 per megawatt hour and average Tier 1 PF Rates were approximately $34.93 per megawatt hour (exclusive of any rate adjustment mechanisms). Under the Final 2024-2025 Rates, average Tier 2 PF Rates are approximately $61.50 per megawatt hour and average Tier 1 PF Rates are approximately $34.69 per megawatt hour. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." The Tier 2 PF Rate does not reflect a long-term commitment, but an election by customers to request that Bonneville serve its Tier 2 Load on a rate period by rate period basis. Prior to Fiscal Year 2020, Bonneville made longer advance purchases to serve its anticipated Tier 2 Loads, but since then Bonneville began and continues to make purchases to serve its Tier 2 Loads closer in time to when Tier 2 elections are made and Tier 2 Load commitments are known (just before the start of each rate period) or, if available, uses its surplus power valued at forward market prices to meet Tier 2 Loads. The Tier 2 Rate increase for the Final 2024-2025 Rates is due to higher forecast market prices for electricity (which is the basis for forecast power purchase costs or the average sales price for surplus sales in each year of the rate period).

Federal System Load/Resource Balance. In order to determine whether Bonneville will have to obtain additional electric power resources on a planning basis, and to determine the amount of firm power that Bonneville may have to market apart from committed loads, Bonneville periodically estimates the amount of load that it will be required to meet under its contracts and compares that to expected generating resources and other supply arrangements.

With the adoption of Bonneville's 2023 Pacific Northwest Loads and Resources Study, Bonneville projected that it would have an energy deficit of approximately 289 annual average megawatts in Operating Year 2025, and an energy deficit of approximately 147 annual average megawatts in Operating Year 2026, assuming Firm Water and transmission line losses. Between Operating Years 2025 and 2033, Bonneville forecasts annual planning deficits that vary between 147 annual average megawatts (in Operating Year 2026) and 424 annual average megawatts (in Operating Year 2033). In Bonneville's opinion, the foregoing deficits do not present significant planning deficits given the size of the Federal System and the availability of various measures to meet such a planning deficit. Bonneville expects that it would be able to meet such a planning deficit with seasonal surplus energy from the Federal System, market purchases, and/or other actions. The foregoing load/resource balance forecast takes into account, among other items (i) forecasts of Federal System generation together with power from purchases, exchanges and other agreements, (ii) forecasts of savings from electric power conservation measures, and (iii) forecasts of the loads of Preference Customers, DSIs, Reclamation, federal agencies other than Reclamation, and contract commitments arising under Other Contract Deliveries.

Bonneville's loads and resources are subject to a number of uncertainties over the coming years. Among these uncertainties are (i) the level of loads and types of loads placed on Bonneville under the provisions of the Northwest Power Act, (ii) the amount of power purchases, resource acquisitions, and other arrangements that Bonneville will have to make to meet contracted supply obligations, (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions, (iv) the availability of existing generation resources, (v) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional load obligations, (vi) changes in the regulation of power markets at the wholesale and retail level, (vii) the overall load growth from population changes and economic activity within the Region, and (viii) evolving transmission system needs to provide ancillary services.

Bonneville's Authority to Acquire Resources. In order to assure it has adequate power supplies to meet its load obligations, Bonneville has authority to acquire resources in addition to the existing Federal System Hydroelectric Projects and existing non-federally-owned generating projects, the output of which Bonneville has acquired by contract. By law, Bonneville may not own or construct generating facilities. However, the Northwest Power Act authorizes Bonneville to enter into contracts for the acquisition of "resources" to serve firm loads pursuant to certain procedures and standards set forth in the Northwest Power Act. "Resources" are defined in the Northwest Power Act to mean: (i) electric power, including the actual or planned electric power capability of generating facilities; or (ii) the actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from conservation measures. "Conservation" is defined in the Northwest Power Act to mean measures to reduce electric power consumption as a result of increased efficiency of energy use, production, or distribution.

Bonneville's statutory responsibility to meet its firm power contractual obligations has led and is expected to lead Bonneville to acquire conservation resources and has led and may in the future lead Bonneville to acquire the output of generation resources. The extent to which Bonneville does so will depend on available resources, the effects of electric power markets, power sales contract terms, forecasted load growth, and other factors.

The authority to acquire resources under the Northwest Power Act, however, is not the sole authority by which Bonneville may meet its power requirements. Other authorities and methods are available. These include, but are not limited to: (i) exchange of surplus Bonneville peaking capacity for firm energy under the Bonneville Project Act; (ii) receipt of additional power from improvements at federally- and non-federally-owned generating facilities; and (iii) short-term purchases of power under the Transmission System Act for periods of less than five years.

Bonneville's resource acquisitions under the Northwest Power Act are guided by a Regional conservation and electric power plan (the "Power Plan") prepared by the Northwest Power and Conservation Council (the "Council"). The governors of the states of Washington, Oregon, Montana, and Idaho each appoint two members to the Council, which is charged under the Northwest Power Act with developing and periodically amending a long range power plan to help guide energy and conservation development in the Region. The Power Plan sets forth guidance for Bonneville regarding conservation and developing generating resources to meet Bonneville's Regional load obligations. It addresses risks and uncertainties for the Region's electricity future and seeks a resource strategy that minimizes the expected cost of the Regional power system over the ensuing 20 years. The Power Plan is revised by the Council approximately every five years. The Council also develops and periodically amends the Council's Fish and Wildlife Program for the Region. See "—Fish and Wildlife—Council's Fish and Wildlife Program."

The Council released its Eighth Northwest Conservation and Electric Power Plan (the "Eighth Power Plan") in February 2022, which provides updated guidance for Bonneville's energy efficiency program in suggested scale of acquisitions and types of most cost-effective energy efficiency. The Power Plan looks forward over a 20-year horizon and includes a six-year action plan for utilities and other parties in the Region, including Bonneville. The Council, Bonneville and other parties around the Region continue to implement provisions of the action plan. The Eighth Power Plan continues to rely on energy efficiency to meet future energy needs and the Council's analysis shows that energy efficiency can meet the Region's expected load growth and calls for the installation of 1,400 average megawatts of energy efficiency by the end of calendar year 2027, including a specific target for Bonneville to acquire between 270 and 360 average megawatts of cost-effective energy efficiency during the six-year period. This is a reduction over the higher levels achieved under the previous plan due to a rapidly changing power system with emerging policies focused on carbon reduction and changing economics driving the rapid adoption of renewable resources. The Eighth Power Plan also recommends the development of demand response resources and use of increased market imports to meet future system capacity needs under critical water and weather conditions.

Based on the Eighth Power Plan and Bonneville's 2022 Resource Program (as defined below), Bonneville drafted an Energy Efficiency Action Plan for the five-year period ending on December 31, 2027. The draft Energy Efficiency Action Plan establishes a target of acquiring 300 average megawatts of energy efficiency by the end of calendar year 2027, and accounts for the priorities set by both the Eighth Power Plan and Bonneville's Resource Program.

Consistent with the Council's analysis, achieving the Council's energy efficiency goal helps Bonneville and other utilities in the Region manage future Regional load growth and minimize reliance on development of other carbon-emitting resources to meet future demand, and will help address future Regional peaking capacity needs. See "—Bonneville's Resource Program and Bonneville's Resource Strategies."

Bonneville's Resource Program and Bonneville's Resource Strategies. Bonneville's long-range resource planning involves the evaluation of whether Bonneville may need to acquire resources to meet its power supply obligations and the best means by which to meet those needs. Bonneville periodically analyzes its needs for annual energy as well as monthly/seasonal heavy load hour energy and capacity in extreme weather events, which inform Bonneville's Resource Program.

Bonneville's most recent Resource Program, which was published in calendar year 2022 (the "2022 Resource Program"), studied Fiscal Years 2024-2034 and found that the Federal System is expected to experience energy deficits in heavy load hours at the average monthly level under low-water conditions, with deficits most pronounced in the winter and late summer. As in prior Resource Programs, the 2022 Resource Program concluded that Bonneville, in addition to existing resources, can satisfy much of its expected supply obligations with electric power conservation and short-term power purchases from wholesale power markets.

Short-Term Power Purchases. Under the Long-Term Preference Contracts, customers may meet their own incremental loads or turn to Bonneville to meet such loads. To meet potential new loads, and consistent with the Resource Program, Bonneville believes that, in general, new sources of power should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available, and should have costs that can be offset when hydroelectric power is available. Short-term purchases are the one type of resource that meets incremental load obligations without incurring long-term fixed costs.

One risk associated with a short-term purchase strategy is the potential for high spot market prices. In general, spot market prices are high when energy demand is strong and coal and natural gas prices are high, although such prices can also rise in low water years when there is comparatively little hydroelectric power available. Since Bonneville's resources are predominantly hydro-based while most other West Coast producers are coal or natural gas-based, Bonneville in general is at a competitive advantage when coal and gas prices are high.

A short-term purchase strategy can lead to fluctuating revenues and/or revenue requirements. In low water years, Bonneville's revenue requirements could increase as it could be forced to spend a significant amount of money for short-term purchases to meet loads, to the extent that Bonneville had not previously purchased power. In high water years, purchase requirements can be significantly reduced as Bonneville would be able to meet more of its loads with seasonal surplus hydroelectric power.

In contrast to a reliance on long-term generating resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville would over-commit to long-term purchases and be forced to sell consequent surpluses at low prices in the market. Nonetheless, it is still possible, even with a short-term purchase strategy, that Bonneville could purchase more energy than needed and have to sell consequent surpluses at low prices. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation. Bonneville uses a short-term energy purchase approach in meeting Tier 2 Loads.

Electric Power Conservation. Bonneville has electric power conservation programs intended to encourage the development of electric power conservation measures in the Region. Electric power conservation can reduce the demand for Bonneville to meet electric power loads. In the 2024-2025 Rate Period, Bonneville forecasts that it will achieve up to 112 average megawatts of conservation.

Renewable Energy. Bonneville presently purchases a total of approximately 33 annual average megawatts from various wind energy projects in Oregon and Washington.

Residential Exchange Program

The Northwest Power Act created the Residential Exchange Program to extend the benefits of low-cost federal power to certain residential and farm power users in the Region that are served by utilities that have high average system costs. In effect, the program results in cash payments by Bonneville to exchanging utilities, which are required to pass the benefit of the cash payments through, in their entirety, to eligible residential and farm customers.

Under the Residential Exchange Program, Bonneville is to "purchase" power offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology defining the costs that may be included in an exchanging utility's average system cost as the production, transmission, and general costs that an exchanging utility incurs for power. Bonneville is then to offer an identical amount of power for "sale" to the utility for the purpose of "resale" to the exchanging utility's residential users. In reality, no power changes hands. Rather, Bonneville makes cash payments to each exchanging utility in an amount determined by multiplying the utility's eligible residential load by the difference between the utility's average system cost and Bonneville's applicable Priority Firm Exchange Rate (which is a version of the PF Preference Rate adjusted for the costs of statutory rate protection afforded to Preference Customers), if such rate is lower.

Bonneville, its Preference Customers, and all six Regional IOUs currently operate under the "2012 Residential Exchange Program Settlement." The settlement fixes the amount of aggregate program benefits and actual aggregate cash payments for the Regional IOUs (plus two Preference Customers) from Fiscal Year 2012 through Fiscal Year 2028. Residential Exchange Program benefits are the nominal financial benefits to be received from Bonneville by an exchanging utility. Actual aggregate cash payments are the actual payments to be paid by Bonneville to an exchanging utility. For the remaining five years of the settlement agreement term, the schedule of aggregate program benefits for the Regional IOUs ranges from $274 million to $286 million per fiscal year. For more details related to Bonneville's Residential Exchange Program commitments, see Appendix B-1 to the Official Statement (Note 10 to the Fiscal Year 2023 Audited Financial Statements).

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate, and enhance fish and wildlife resources to the extent they are affected by the Federal System Hydroelectric Projects, which are located on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife in a manner consistent with the Northwest Power Act and the Council's Fish and Wildlife Program. See "—Council's Fish and Wildlife Program." In addition, in the wake of certain listings of fish species under the ESA as threatened or endangered, Bonneville is financially responsible for expenditures and other costs arising from compliance with the ESA and certain biological opinions prepared by NOAA Fisheries and the Fish and Wildlife Service in furtherance of the ESA.

Bonneville typically funds fish and wildlife mitigation through several mechanisms. Since the creation of the Federal System, Bonneville has repaid the United States Treasury the share of the costs of mitigation by the Corps and Reclamation that is allocated by law or pursuant to policies, promulgated by FERC's predecessor, to the Federal System projects' power purpose (as opposed to other project purposes such as irrigation, navigation, and flood risk management).

Bonneville also funds and implements fish and wildlife mitigation measures that are consistent with the Council's Fish and Wildlife Program and the other purposes of the Northwest Power Act. The Council's Fish and Wildlife Program calls for a variety of mitigation measures from habitat protection to main-stem Columbia River and Snake River operations for fish. When such measures require Bonneville to purchase power to fulfill contractual demands or to spill water and thereby forgo generation of electricity, for instance, those financial losses are counted as a cost of the measures borne by Bonneville. While many of the measures in the Council's Fish and Wildlife Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's Fish and Wildlife Program measures, especially those designed to benefit species not listed under the ESA, are in addition to ESA-directed measures. See "—Council's Fish and Wildlife Program."

Bonneville's fish and wildlife costs fall into two main categories, "Direct Costs" and "Operational Impacts." Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing projects in support of the Council's Fish and Wildlife Program, and which include expenses for ESA-related and some non-ESA-related measures that are located at sites away from the Federal System Hydroelectric Projects, (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps (Columbia River Fish Mitigation), Reclamation, and Bonneville, and (iii) Other Entities' Operations & Maintenance ("O&M")," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation for Federal System projects. Columbia River Fish Mitigation is described in "—The Endangered Species Act."

Operational Impacts include "Replacement Power Purchase Costs" and "Foregone Power Revenues." Replacement Power Purchase Costs are the costs of certain power purchases made by Bonneville that are attributable to river operations in aid of fish and wildlife. To determine these costs in a given year, Bonneville compares the actual hydroelectric generation in such year against the hydroelectric generation that would have been produced had the Federal System Hydroelectric Projects been operated without any operating constraints due to fish and wildlife protection. To the extent that this comparison indicates that Bonneville made a power purchase to meet load, which purchase Bonneville would not have had to make had the river been operated without the constraints identified for fish, Bonneville accounts for such value as a fish and wildlife cost. Conversely, if the comparison indicates that Bonneville made fewer power purchases than would have been made had the river been operated without the constraints identified for fish, Bonneville accounts for such value as a negative fish and wildlife cost. "Foregone Power Revenues" are revenues that would have been earned absent changes in hydroelectric system operations attributable to fish and wildlife measures. The following table shows Bonneville's Fish and Wildlife costs by category for Fiscal Years 2021 through 2023.

Fish and Wildlife Financial Impacts by Type
(Unaudited)(2)
(Fiscal Years 2021-2023, dollars in millions)

	2023	2022	2021
Direct Costs	$ 463	$ 451	$443
Estimated			
Replacement Costs	879	238	111
Foregone	89	252	191
Total Fish	**$ 1,431**	**$ 941**	**$ 745**

(1) Unaudited metric that is not in accordance with GAAP.
(2) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

The variations in Direct Costs from year to year are the result of changes in reimbursable/direct-funded projects and fixed expenses. The variations in Replacement Power Purchase Costs and Foregone Power Revenues are the result of changes in prices due to energy market conditions, differences in monthly hydro generation shape, and changes in hydroelectric system operations resulting from biological opinions and related actions under the ESA (as described immediately below).

The Endangered Species Act. Operation of the Federal System Hydroelectric Projects by the Action Agencies is subject to the ESA. To a great extent, compliance with the ESA determines how the Federal System Hydroelectric Projects are operated to benefit fish and drives much of the fish planning and activities. The ESA listings and biological opinions have resulted in major changes in the operation of the Federal System Hydroelectric Projects, including a substantial loss of flexibility to operate the Federal System for power generation. Apart from changes in Federal System Hydroelectric Project operations that affect power generation, compliance with the ESA has also resulted in additional costs borne by Bonneville in the form of non-operational measures for the conservation of fish species funded from Bonneville revenues. Among other things, the ESA requires that federal agencies such as the Action Agencies ensure their actions are not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. Since 1991, over a dozen anadromous and other marine species (including multiple stocks of salmon and steelhead, Southern Resident killer whales, North American green sturgeon, and eulachon) and two species of resident fish (bull trout and Kootenai River white sturgeon) that are affected by operation of the Federal System Hydroelectric Projects have been listed as threatened or endangered under the ESA. It is possible that other species may be listed or proposed for listing in the future. In general, the effect of the listing of the fish species under the ESA, and certain other operating requirements resulting from Bonneville's fish and wildlife obligations under the Northwest Power Act, is that, except in emergencies, the Federal System Hydroelectric Projects on the Columbia and Snake Rivers are now operated for power production only after meeting needs for flood risk management and the protection of ESA-listed fish.

In connection with the listing of these species, NOAA Fisheries has prepared certain biological opinions addressing Federal System Hydroelectric Project operations with respect to the listed anadromous salmonid species, and the Fish and Wildlife Service has developed biological opinions with respect to the listed resident fish species. These biological opinions provide information that the Action Agencies use to ensure that their actions with respect to the operation of the Federal System Hydroelectric Projects comply with the ESA. By operating the Federal System Hydroelectric Projects consistently with the biological opinions, the Action Agencies demonstrate that operation of the Federal System Hydroelectric Projects is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

As described herein, the Action Agencies' compliance with the ESA in operating the Federal System Hydroelectric Projects has been the subject of litigation and judicial review and has resulted in court orders remanding biological opinions, including the 2014 Columbia River System Supplemental Biological Opinion for the Columbia and Snake Rivers. Operation of the Federal System Hydroelectric Projects consistent with the ESA has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise run through dam turbines to generate electricity may be spilled to aid in downstream fish migration. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration. Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these limitations, under certain water conditions, Bonneville has purchased and will purchase additional energy for the fall and winter to meet load commitments that would otherwise have been met with electric power from the Federal System Hydroelectric Projects. In addition, the flow changes have reduced the surplus energy Bonneville has available to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System Hydroelectric Projects in conformance with the biological opinions and the Council's Fish and Wildlife Program, as in effect as of the beginning of Fiscal Year 2000, decreased Federal System hydroelectric generation capability by approximately 1,000 annual average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the NOAA Fisheries biological opinion in 1995. The consequences of this and similar ESA-related decrements in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues. See "—General" immediately above.

These ESA listings and related actions to protect listed species and their habitat have resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville's annual fish and wildlife mitigation costs increased from approximately $20 million in Fiscal Year 1981 to $150 million in Fiscal Year 1991. After the issuance of the first biological opinion affecting operations of the Federal System Hydroelectric Projects, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in Fiscal Year 1995. Annual fish and wildlife costs borne by Bonneville in recent fiscal years are described immediately above in "—General." Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council's Fish and Wildlife Program, discussed below. Bonneville is also continuing to provide funding under agreements with certain tribes and the states of Idaho, Montana, and Washington, including through updates and extensions to the Columbia Basin Fish Accords. See "—The Columbia Basin Fish Accords and Related Agreements," below.

Description of the 2014 Columbia River System Supplemental Biological Opinion and the 2020 Columbia River System Biological Opinions. As noted herein, litigation challenging the 2014 Columbia River System Supplemental Biological Opinion resulted in a determination, by the District Court, that it did not meet the requirements of the ESA or NEPA. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." The District Court directed that the Corps and Reclamation continue to implement the 2014 Columbia River System Supplemental Biological Opinion until issuance of a new environmental impact statement and biological opinion.

Since the 2014 Columbia River System Supplemental Biological Opinion expired of its own terms and the agreed to spring spill operations modified the federal agency action in a way not considered in the 2014 Columbia River System Supplemental Biological Opinion, the Action Agencies reinitiated consultation with NOAA Fisheries in 2018. The Action Agencies' proposed action was largely a continuation of the actions from the 2008-2018 time period, including tributary habitat improvement actions, estuary habitat measures, hatchery mitigation measures, predation management, and research and monitoring actions. An interim NOAA Fisheries biological opinion was effective on April 1, 2019 to cover operations and maintenance of the Columbia River System until the 2020 Columbia River System Biological Opinions were implemented in September 2020.

The Final CRSO EIS, issued on July 31, 2020, included the 2020 Columbia River System Biological Opinions. On September 28, 2020, Bonneville and the other Action Agencies issued the CRSO EIS Record of Decision adopting the Preferred Alternative in the Final CRSO EIS as the Selected Alternative (the "Selected Alternative") and implementing the consistent action consulted upon in the biological opinions. The 2020 Columbia River System Biological Opinions evaluated impacts of the Action Agencies' proposed action, which is consistent with the Selected Alternative, on 13 species of salmon and steelhead along with other species listed under the ESA and found that the Selected Alternative is not likely to jeopardize the continued existence of the ESA-listed species or destroy or adversely modify their designated critical habitat.

The Action Agencies considered six alternative courses of action and studied the environmental, economic and social impacts of such alternatives. The range of alternatives considered included a No Action Alternative and an alternative that included breaching the four lower Snake River dams. Dam breaching was not included as part of the Selected Alternative and it is the opinion of the General Counsel to Bonneville that breaching or other similar major structural changes eliminating one or more of the congressionally authorized purposes of any of the federal dams of the Federal System would require Congressional enactment authorizing such action.

The Selected Alternative results in a reduction of 160 annual average megawatts of hydropower generation from the Columbia River System projects over the No Action Alternative; however, an equivalent level of reduction in hydropower generation was implemented under the 2019-2021 spill operation agreement. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." Under the Selected Alternative, the Federal System overall is estimated to lose approximately 300 annual average megawatts of firm power available for long-term, firm power sales to Preference Customers under critical water conditions compared to the No Action Alternative; however, due to the seasonal shape of generation changes (less generation in spring, slightly more in winter and late August) the regional power system reliability will be roughly the same as under current operations and no replacement resources are expected to be needed for reliability.

As part of stay negotiations in the Columbia River System litigation in 2021, the Action Agencies agreed to specific changes to planned 2022 fish passage operations. Bonneville evaluated the effects of these operational changes and found there would be minimal change in effects compared to the Selected Alternative. Under average water conditions, 2022 fish passage operations were expected to reduce the annual average megawatts of hydropower generation from the Columbia River System projects as compared to the Selected Alternative by 45 annual average megawatts. The parties subsequently agreed to 2023 fish passage operations, which are similar to those in effect for 2022 fish passage operations. In December 2023, the Biden Administration announced the December 2023 Agreement, an agreement to work in partnership with Pacific Northwest Tribes and States to further the restoration of native fish populations, expand Tribally sponsored clean energy production, and provide stability for communities that depend on the Columbia River System. The operations subject to the December 2023 Agreement are also similar to the effects for the 2022 and 2023 fish passage season, with the addition of the earlier start of both March surface spill operations, which will have a minor impact on available generation, and the summer spill reduction, which is likely to lead to more available generation in August than recent operations.

In addition to estimated impacts on hydropower generation, the Selected Alternative also includes certain structural modifications to Federal System hydroelectric dams. Amounts needed for construction of the structural modifications would be provided to the Corps and Reclamation either through direct funding or appropriated by Congress to the

Corps or Reclamation (primarily related to the Columbia River Fish Mitigation program) and capitalized and recovered in Bonneville's rates over a period of 50 years.

Bonneville's authority to enter into the December 2023 Agreement is being challenged in court. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Impacts on Bonneville's Rates. In developing the Final 2024-2025 Rates, Bonneville made certain assumptions of the expected incremental costs that would arise from implementation of the 2020 Columbia River System Biological Opinions to assure full cost recovery in Bonneville's rates. Bonneville's proposed power rates include, and its power rates for the past several rate periods have included, certain rate level adjustment provisions that enable Bonneville to increase rate levels within a rate period when Power RAR levels fall below certain cash on hand thresholds. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025."

The National Environmental Policy Act and the Endangered Species Act. NEPA requires that federal agencies evaluate the environmental impacts of their proposed actions and make this analysis available to the public. NEPA is procedural in the sense that it does not require a particular outcome for a decision, but it does mandate a process for taking a "hard look" at environmental consequences of, and alternatives to, an agency's proposal. Depending on the circumstances, NEPA may require that the federal government prepare an environmental impact statement prior to making a decision to undertake an action. Preparation of an environmental impact statement can be time consuming and the associated analysis can be extensive, depending on the complexity of the proposed actions and the potential effects on the environment.

The Columbia River Fish Mitigation Program. As noted above, the Action Agencies are currently implementing actions consistent with the 2020 NOAA Fisheries Columbia River System Biological Opinion. The 2020 NOAA Fisheries Columbia River System Biological Opinion carries forward from prior biological opinions plans for completion of structural modifications to Federal System hydroelectric dams. These modifications have been and are expected to be funded by specific federal appropriations, primarily to the Corps under the "Columbia River Fish Mitigation" program. Bonneville expects that it will be responsible for recovering in its power rates as a repayment to the United States Treasury approximately 80 percent of the costs of the federally appropriated modifications to the Federal System Hydroelectric Projects on the Columbia River and Snake River, which is the estimated portion of such costs assigned by law or administrative practice to be recovered in Bonneville's power rates. Bonneville does not expect that the modifications will be financed with Bonneville's statutory borrowing authority with the United States Treasury. As with other appropriated investments in the Federal System, Bonneville depreciates the portion of the costs to be recovered in power rates, for 50 years in most cases, from the dates the related capital facilities are placed in service or the regulatory asset is completed. These studies and modifications have been funded over many years; thus, their costs have been and will be gradually added to Bonneville's rates and statutory repayment obligations that Bonneville has for amounts appropriated by Congress for federally-owned hydroelectric and transmission facilities of the Federal System ("Federal Appropriations Repayment Obligations") as they are completed and placed in service.

As of the end of Fiscal Year 2023, Bonneville was responsible for approximately $1.0 billion of Columbia River Fish Mitigation costs, as allocated to the power purpose of the Corps' Federal System Hydroelectric Projects. Under the Corps' current plan covering five years, the Columbia River Fish Mitigation program would obtain additional appropriations for continued funding of modifications and increase the amount expected to eventually be assumed by Bonneville as repayable appropriations obligations by approximately $115 million through Fiscal Year 2028. This would bring the total amount of Bonneville's Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation to approximately $1.1 billion by the end of Fiscal Year 2028. The amounts ultimately appropriated under the Columbia River Fish Mitigation program (through Fiscal Year 2028 and in future years) may be greater depending on possible changes to the Corps' current five year plan, the Corps' plans for years beyond Fiscal Year 2029, requests for appropriations by the Corps and Congressional enactments of appropriations. The expected costs associated with such additional Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation will begin to be recovered in Bonneville's power rates when the related investments are placed in service, which depends on the timing and amounts of appropriations and the time required by the Corps to bring multi-year projects to completion. Other federally appropriated amounts may be added to Bonneville's Federal Appropriations Repayment Obligations from time to time depending on specific project appropriations received by the Corps and Reclamation for Federal System investments. See "BONNEVILLE FINANCIAL OPERATIONS—The Federal System Investment."

Bonneville is unable to predict the effects, if any, that the 2020 NOAA Fisheries Columbia River System Biological Opinion will have on the types and timing of Federal System investments (including but not limited to investments under the Columbia River Fish Mitigation program) for which Congressional appropriations will be requested and enacted, the amounts appropriated therefor, and the amounts that would be included for recovery in Bonneville's rates for power. See "BONNEVILLE FINANCIAL OPERATIONS—The Federal System Investment."

The Columbia Basin Fish Accords and Related Agreements. Beginning in 2008, Bonneville, the Corps, and Reclamation entered into seven separate agreements with a number of Regional interests including six tribes, an inter-tribal association, and the states of Washington, Montana and Idaho. These agreements, collectively known as the Columbia Basin Fish Accords, assured long-term mitigation funding to address Federal System Hydroelectric Projects' effects on fish and wildlife, and have helped the Action Agencies protect, mitigate, and enhance fish and wildlife in the Columbia River basin and address the Action Agencies' responsibilities for ESA-listed fish.

Bonneville estimates that most of its funding commitments under the Columbia Basin Fish Accords have been and will be for work necessary to implement actions associated with biological opinions for the Federal System Hydroelectric Projects and for work that otherwise addresses federal statutory fish and wildlife mitigation responsibilities such as those under the Northwest Power Act.

Certain of the agreements comprising the Columbia Basin Fish Accords have been amended and extended several times, most recently in 2022. Bonneville's total remaining commitment through 2025 for the Columbia Basin Fish Accords is approximately $482 million. This total includes approximately $172 million in remaining commitments from the prior agreements and $310 million in additional commitments from Fiscal Years 2024 and 2025. This also includes the funding commitments in a related agreement between Bonneville and the Kootenai Tribe of Idaho through 2025. For details related to the current total outstanding Columbia Basin Fish Accords and similar commitments, see Appendix B-1 to the Official Statement (Note 14 to Financial Statements).

In addition to the pre-existing Columbia Basin Fish Accords commitments described above, Bonneville recently entered into a new agreement with the Coeur D'Alene Tribe. Bonneville's commitment in this new agreement is approximately $163 million through Fiscal Year 2033. A similar new agreement between Bonneville and the Spokane Tribe of Indians is expected to be signed in early May of 2024. Under that pending agreement, Bonneville's commitment would be approximately $148 million through Fiscal Year 2033. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

The Columbia Basin Fish Accords do not include long-term funding arrangements relating to wildlife mitigation in the Willamette basin and northern and southern Idaho.

Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible future changes in Federal System dams or dam operations, under the ESA or other environmental laws.

Willamette River Basin. The Corps owns and operates 13 dams in the Willamette River Basin (the "Willamette Project") for the purposes of flood risk reduction, hydropower (at eight dams), recreation, and water supply. The Willamette Project is included in the Federal System. Bonneville markets the power from the Willamette Project and funds the Corps for the power purpose share of both capital and operations and maintenance costs at the facilities of the Willamette Project. Bonneville estimates that, prior to recent litigation described below, approximately 197 megawatts of power were produced by the Willamette Project under average water conditions. In December 2020, Congress directed the Corps to study de-authorization of the power purpose at three Willamette dams (Big Cliff, Cougar, and Detroit). The Corps has not yet made any findings available for public review. In December 2022, Congress directed the Corps to complete a disposition study of the power purpose at the Willamette Project no later than June 2024. If a decision were made to seek de-authorization of the power purpose at any of the Willamette Project dams, Congress would need to pass legislation authorizing such action. It is unknown at this time whether Bonneville would be relieved of the commitment to fund future costs related to de-authorized dams or if such reduction in power production would require Bonneville to acquire additional resources to meet its future load obligations.

Willamette River Basin Flood Control Project Biological Opinion. NOAA Fisheries issued in 2008 its Willamette River Basin Flood Control Project Biological Opinion (the "2008 Willamette BiOp"). The 2008 Willamette BiOp evaluated the impact of ongoing operations of the Willamette Project on fish species that are listed under the ESA as threatened or endangered, and concluded that certain species were in jeopardy and their critical habitat was likely to be adversely modified or destroyed. The 2008 Willamette BiOp was also adopted in a separate biological opinion by the Fish and Wildlife Service.

To fulfill the requirements of the 2008 Willamette BiOp related to downstream passage and water temperature control, the Corps first instituted a variety of operational changes and, after securing funding, modified or constructed a host of facilities. The Corps also carried out a multi-year, multi-level study process, known as the Configuration and Operation Plan or "COP," to evaluate a range of potentially beneficial actions for listed fish species at Willamette dams and reservoirs, including for long-term downstream passage and temperature control. The results of the COP provided a plan of action for potential downstream fish passage facilities at Cougar and Detroit dams (and temperature control at Detroit dam). These facilities were not constructed at that time.

On March 13, 2018, three environmental protection organizations filed an action against the Corps and NOAA Fisheries in the District Court with respect to operation and maintenance of the Willamette Project related to decision making, hatcheries, downstream passage, and water quality. Specifically, the plaintiffs sought reinitiation of consultation under Section 7 of the ESA, in part due to the Corps' failure to construct the fish passage facilities contemplated in the 2008 Willamette BiOp, which could result in changes to or replacement of action items that could further increase costs to Bonneville. After numerous court hearings on various motions, the District Court issued a draft order on July 14, 2021, ordering injunction measures to be refined with the input of an expert panel. The proposed injunction measures included fall/winter reservoir drawdowns at Cougar, Green Peter, Look Out, and Fall Creek dams; fish passage and water quality operations at several projects; and spill operations. A final order was issued by the District Court on September 1, 2021, adopting the remedy measures contained in the draft order and finalizing the composition of the expert panel, a mix of federal and plaintiff experts. In the final order, the District Court also held that the Corps has the authority to eliminate the reserved power pool (reservoir elevations at Willamette Project dams reserved for power generation during the months of October through April) to benefit ESA-listed fish species.

The federal government began implementing the court-ordered measures in November 2021. Among them are an operation to withdraw water through non-power outlets at Detroit Dam and a draw down at Cougar Dam which eliminate most or all electricity generation in fall and winter months. Delayed refill in the spring greatly diminished power generation at Cougar Dam in the spring of 2022 and is expected to have a similar impact in subsequent years. Similar reservoir drawdowns occurred at Look Out Point Dam and Green Peter Dam in the fall of 2023. In aggregate, implementation of all of the court-ordered measures is expected to reduce the total electricity generated at the Willamette Project by about one-third.

The Corps, Bonneville and Reclamation reinitiated consultation with NOAA Fisheries and the Fish and Wildlife Service in April 2018 on a new biological opinion (the "2024 Willamette BiOp"). The Corps concurrently initiated a new environmental analysis under NEPA on a Programmatic Environmental Impact Statement to address the continued operations and maintenance of the Willamette Valley System (the "Willamette EIS"). The fish passage facilities which were contemplated in the 2008 Willamette BiOp but not constructed are now included as a suite of projects being evaluated in the Willamette EIS. The District Court retains jurisdiction over the remedy injunction until the 2024 Willamette BiOp is completed, anticipated no later than December 31, 2024.

Under Bonneville's existing appropriations repayment criteria, after any proposed structural modifications are placed in service, it is expected that a portion of the amounts appropriated for such purposes will be included in Bonneville's Federal Appropriations Repayment Obligation for recovery in Bonneville's rates. The proportion of the overall Willamette Project's fish mitigation costs that are assigned to be recovered in Bonneville's power rates is approximately 42 percent. Under the applicable repayment criteria, the costs, which include study, design, and construction costs, would be recovered in Bonneville's rates over a period of 75 years from the dates that related modifications are placed in service.

Bonneville expects there to be an increase in the all-in costs of the Willamette Project power (which include but are not limited to fish mitigation measures such as streamflow enhancements and fish habitat/hatchery improvements under the 2008 Willamette BiOp and any possible future changes that may arise as a result of the reinitiated ESA Section 7 consultation or otherwise). The new ESA Section 7 consultation could result in additional proposed structural modifications, operational changes, or other measures. Although Bonneville can make no prediction of the total costs or consequences to it with respect to the Willamette Project arising under the ESA, Bonneville intends to mitigate any upward rate pressure, to the extent possible, through offsetting cost reductions in other Bonneville programs.

Willamette River Basin Memorandum of Agreement Regarding Wildlife Habitat Protection and Enhancement. Bonneville and the State of Oregon have signed an agreement that, upon successful completion, permanently fulfills Bonneville's longstanding wildlife mitigation obligations under the Northwest Power Act associated with the Willamette River dams. Bonneville's total commitment under the agreement is $144 million (including inflation) through Fiscal Year 2025. In addition, Bonneville will provide some level of additional funding for the Oregon Department of Fish and Wildlife's operations and maintenance costs with respect to the Willamette Project for Fiscal Year 2026 through Fiscal Year 2043. Bonneville will negotiate its funding obligations based on historical funding levels and contemporaneous needs and conditions.

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the United States Office of Management and Budget ("OMB"), DOE, and other agencies agreed to provide for certain federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision authorizes Bonneville to exercise its Northwest Power Act authority to implement fish and wildlife mitigation on behalf of all of a Federal System Hydroelectric Project's authorized purposes under federal law; not just those relating to the delivery of generation and transmission services to customers, but also non-power purposes such as irrigation, navigation, and flood control. At the end of the fiscal year, Bonneville is required to recoup (i.e., take a credit for) the portion allocated to non-power purposes. Included in this credit are Direct Costs and estimated Replacement Power Purchase Costs. The amount of such recoupments (also referred to as "4(h)(10)(C) credits") was approximately $91 million, $112 million, and $258 million in Fiscal Years 2021, 2022, and 2023, respectively. Forecasts of these 4(h)(10)(C) credits are treated as revenues in Bonneville's ratemaking process. At the close of each fiscal year, they are applied against Bonneville's payments to the United States Treasury. The 4(h)(10)(C) credits are initially taken based on estimates and are subsequently modified to reflect actual data. An important cost that may be recouped under section 4(h)(10)(C) is that of Replacement Power Purchases necessitated by the loss of generation arising from certain changes to hydroelectric system operations for the benefit of fish and wildlife. These costs occur annually and are highest in low water years when, historically, the hydroelectric output of the Federal System is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

Council's Fish and Wildlife Program. In 2015, the Council amended the Columbia River Basin Fish and Wildlife Program (the "Council's Fish and Wildlife Program") to recommend actions to mitigate the impacts of the operation of the hydroelectric dams of the Federal System on fish and wildlife in the Region, as provided under the Northwest Power Act. In general, Bonneville is charged with protecting, mitigating, and enhancing fish and wildlife affected by the Federal System in a manner consistent with the Council's Fish and Wildlife Program, the Council's Power Plan, and the other purposes of the Northwest Power Act. The Council's Northwest Power Act mitigation recommendations include the actions in the Columbia Basin Fish Accords and biological opinions as well as other measures to protect fish and wildlife. The Council amended its fish and wildlife program in the fall of 2020. The amendment was largely intended to clarify, reorganize and supplement the program, but not amend or replace the existing program.

In view of the increasing number of actions under the ESA in connection with listed fish populations affected by the Federal System, and in view of the potential for overlap or conflict of ESA-related actions with recommendations under the Council's Fish and Wildlife Program, beginning in the late 1990s, the Council began integrating ESA and Clean Water Act compliance actions into the Council's Fish and Wildlife Program. The costs of this "Integrated Program" are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—General." In Fiscal Year 2023, Integrated Program expense was $289 million, and Federal System capital investment was

$15 million. Bonneville forecasts that Fiscal Year 2024 Integrated Program expense and Federal System capital investments will be $313 million and $42 million, respectively.

Bonneville believes its current levels of funding fulfill all of its statutory responsibilities related to fish and wildlife; however, Bonneville cannot provide assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System Hydroelectric Projects (and other components of the Federal System), including measures resulting from current and future listings under the ESA, current and future biological opinions or amendments thereto, future Council programs or amendments thereto, or litigation relating to the foregoing.

Power Rates for Fiscal Years 2024-2025

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's Final 2024-2025 Rates for power and transmission rates of general applicability and FERC has granted final approval thereof. The final Tier 1 PF Rates for the 2024-2025 Rate Period for power sold to Preference Customers for their requirements vary depending on the particular power product provided by Bonneville. Average base Tier 1 PF Preference Rates (inclusive of the Slice, Block and Load Following products) decreased by less than one percent from the prior average rates to $34.69 per megawatt hour. Under the Final 2024-2025 Rates, average Tier 2 PF Rates (which apply to certain incremental loads that Preference Customers require Bonneville to meet) increased by 83 percent, to $61.50 per megawatt hour when compared to Average Tier 2 PF Rates in effect in the prior rate period. For additional details regarding Tier 1 PF Rates and Tier 2 PF Rates, see "—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Comparison of Tier 1 PF Rates and Tier 2 PF Rates."

The Final 2024-2025 Rates continue use of a CRAC. The CRAC mechanisms implemented in the Final 2024-2025 Rates are similar to the CRAC for the 2022-2023 Rate Period. An increase in power rate levels under the CRAC would occur if certain financial information resulted in Power Services' expenses that were higher and/or revenues that were lower than anticipated that resulted in Power Services' RAR falling below certain thresholds as of September 30.

The CRAC enables Bonneville to increase certain power and related rate levels over base rates to obtain up to $300 million in additional revenue in each of the two fiscal years of the rate period, without a time-consuming rate proceeding, if Power Services' RAR are below zero at the beginning of either fiscal year in the rate period. The amount of additional revenue to be obtained under the CRAC in a fiscal year would be established, in general, to be the amount of the difference between zero and the Power Services' RAR at the beginning of the fiscal year in which the CRAC is evaluated for implementation (this differential is referred to herein as the "CRAC Underrun"). More particularly, the CRAC would be used to obtain in a fiscal year: (i) all of the first $100 million of a Power CRAC Underrun, if any, for such fiscal year, and (ii) one half of any remaining Power CRAC Underrun for such fiscal year, up to a maximum of $200 million. Such amounts would be reduced by the amount of planned revenue financing, if any, for such fiscal year. The CRAC terms include a *de minimis* provision under which Bonneville would not trigger the CRAC for implementation for a fiscal year unless the CRAC Underrun were to exceed $5 million.

Also included in the Final 2024-2025 Rates, Power Services rates continue to make available a surcharge rate adjustment mechanism (the "FRP Surcharge") to implement Bonneville's Financial Reserves Policy and rate actions to raise RAR levels when they fall below a specified level for each business line. An increase in Power Services rate levels under the Financial Reserves Policy Surcharge would occur if Power Services' RAR falls below certain thresholds as of September 30. The thresholds for each business line are equivalent to the amount of cash needed to meet operating expenses for 60 days. For Power Services, the forecast amount of cash expected to be needed to meet its operating expenses for 60 days is $319 million. The Financial Reserves Policy Surcharge would allow Bonneville to increase certain power and related rates over base rates to obtain up to $40 million of additional revenue if Power Services' RAR were below $319 million at September 30, 2024. The FRP Surcharge terms include a *de minimis* provision under which Bonneville would not trigger the FPR Surcharge for implementation for a fiscal year unless the underrun were to exceed $5 million.

Neither a CRAC nor a Financial Reserves Policy Surcharge, included in the Final 2024-2025 Rates, triggered at September 30, 2023 for application to Fiscal Year 2024 power rate levels. If a Power CRAC or FRP Surcharge were to trigger for application to Fiscal Year 2025 power related rate levels, Bonneville would notify customers by November 30, 2024.

The Final 2024-2025 Rates for Power Services continue the availability of the RDC, which has triggered for application to certain power rates and transmission rates in Fiscal Year 2024. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates." Bonneville's decision regarding application of the Fiscal Year 2023 Power RDC is being challenged in court. See "BONNEVILLE LITIGATION—Fiscal Year 2023 Power RDC Challenge." Under the Final 2024-2025 Rates, Bonneville also reserved the ability to institute another full rate proceeding and increase rates or rate levels in the rate period, which Bonneville has estimated would take several months.

The risk mitigation tools underlying the power rates also include relying on certain RAR derived from Power Services operations and relying on the availability of funds, if needed during the rate period, under Bonneville's $750 million short-term credit facility with the United States Treasury, to cover certain operating expenses. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics," and "—Banking Relationship between the United States Treasury and Bonneville."

Historical PF Preference Rate Levels

As shown in the following chart, Bonneville's average PF Preference Rates have remained between $20 per megawatt hour and $37 per megawatt hour in nominal (actual) dollars, and between $16 per megawatt hour and $29 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2023. These estimates include average PF Preference Rates expressed on a dollar-per-megawatt-hour basis, exclusive of Slice rates. While most PF Preference Rates are established on a dollar-per-megawatt hour basis, Slice rates are set on the basis of dollars-per-percentage-point of Slice. The data also exclude PF Exchange Rates which are used in determining Residential Exchange benefits, and Tier 2 PF Rates, which Bonneville instituted in Fiscal Year 2012 to recover the cost of meeting certain incremental loads.

Bonneville's average PF Preference Rates increased substantially in Fiscal Year 2002 to recover costs incurred during and as a result of the West Coast energy crisis in 1999-2001. Since then, such rates have been stable, especially when viewed from an inflation-adjusted perspective, as shown in the following chart.

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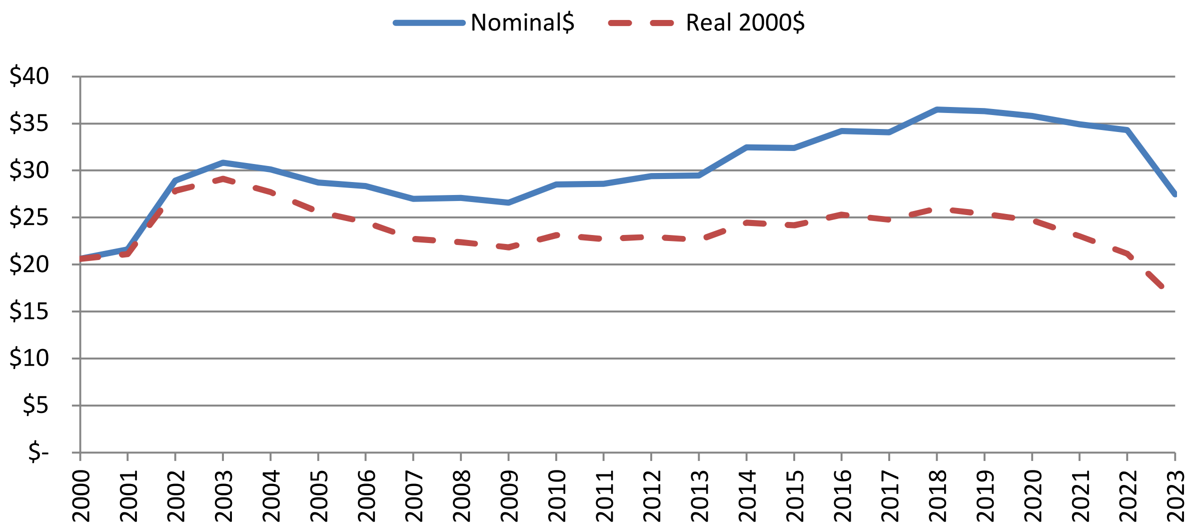
Historical Average PF Preference Rates

Nominal (Actual) and Real (Inflation-Adjusted) Average PF Preference Rate Levels,

Per Megawatt Hour, Fiscal Years 2000—2023



Recovery of Stranded Power Function Costs

As a consequence of regulatory and economic changes in electric power markets, many utilities see potential for certain of their costs, in particular power system costs, to become unrecoverable or "stranded." Stranded costs may arise where power customers are able, pursuant to open transmission access rules, to reach new sources of supply, leaving behind unamortized power system costs incurred on their behalf. Bonneville could also face this concern. While Bonneville has separate statutory authority requiring it to assure that its revenues are sufficient to recover all of its costs, additional authority may be required to assure that such costs, including Bonneville's payments to the United States Treasury, are made on time and in full. Depending on the exact nature of wholesale and retail transmission access, it is possible that Bonneville's power marketing function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. Nonetheless, Bonneville cannot predict with certainty its cost of power or market prices.

FERC's 1996 order, "Order 888," to promote competition in wholesale power markets, established standards that a public utility under the Federal Power Act ("FPA") must satisfy to recover stranded wholesale power costs. The standards contain limitations and restrictions, which, if applied to Bonneville, could affect Bonneville's ability to recover stranded costs in certain circumstances. However, Bonneville's General Counsel interprets FERC Order 888 as not addressing stranded cost recovery by Bonneville under either the Northwest Power Act or sections 211 and 212 of the FPA. For a discussion of Order 888 and sections 211 and 212 of the FPA, as amended by Energy Policy Act of 1992 ("EPA-1992"), see "TRANSMISSION SERVICES—FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services."

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211 and 212 of the FPA are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under FPA sections 211 and 212.

Shortly after the issuance of Order 888-A, Bonneville requested clarification of the application of FERC's stranded cost rule to Bonneville in the context of an order for transmission service under sections 211 and 212. In FERC Order 888-A, modifying original FERC Order 888, FERC addressed Bonneville's request by stating: "We clarify that our review of stranded cost recovery by [Bonneville] would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate [Bonneville] . . . and/or section 212(i), as appropriate." Therefore, it remains unclear how FERC would intend to balance Bonneville's Northwest Power Act cost recovery standards with the stranded cost rule as enunciated in FERC Order 888 in the context of FERC ordered transmission service pursuant to sections 211 and 212. Contrary to the opinion of Bonneville's General Counsel, several of Bonneville's transmission customers have taken the position that transmission rates may not be set to recover stranded power costs as Bonneville envisions under the Northwest Power Act.

Under the Energy Policy Act of 2005 ("EPA-2005"), FERC was granted authority to require that the rates for transmission service that Bonneville provides to itself be comparable to the rates it charges others. The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act but must be balanced with them. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville, notwithstanding the enactment of EPA-2005. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

TRANSMISSION SERVICES

Bonneville provides a number of different types of transmission services to Preference Customers, Regional IOUs, DSIs, other privately and publicly owned utilities, power marketers, power generators, and others. Transmission Services earned approximately $1.2 billion in revenues from the sale of transmission and related services, or approximately 27 percent of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2023.

Bonneville's Transmission Services provides transmission service under its Open Access Transmission Tariff ("Tariff"). Two transmission services are offered under the Tariff: Point-to-Point and Network Integration. These services are available to all customers regardless of whether they are transmitting federal power (in effect, power from the Federal System) or non-federal power. Network Integration service is used by many Preference Customers (as well as others) for delivery of federal and non-federal power to their loads. Point-to-Point service is typically taken by power marketers, independent power producers, and certain large utility customers. Finally, Bonneville, as a partial owner of the northern portions of the Southern Intertie and southern portion of certain transmission lines connecting areas of western Canada with the Region, provides Point-to-Point service to power marketers, including Bonneville's Power Services, which use Bonneville transmission service to support power sales and related transactions inside and outside the Region. Bonneville's Transmission Services also provides reservation-based service under "legacy contracts"; that is, those that were in effect when Bonneville adopted open access in the mid-1990s. As these contracts expire, the service converts to Tariff services.

It is difficult to generalize as to a Preference Customer's cost of Network Integration service needed to effect various power transactions because the charge is based on actual usage and thus can vary from month to month and customer to customer. Nonetheless, a useful point of reference for the proportion that power rates bear to transmission and ancillary services rates may be the cost borne by certain Preference Customers that purchase Full Requirements power from Bonneville. For example, in the current rate period (Fiscal Years 2024-2025), a large Preference Customer that purchases very little transmission for its own generating resources pays Bonneville approximately $4.74 per megawatt hour for transmission service and approximately $34.69 per megawatt hour for electric power (excluding the effect of any rate adjustment mechanisms).

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System, which is operated and maintained by Bonneville and owned or leased by Bonneville, as well as the Federal System Hydroelectric Projects, and certain non-federal power resources. The Federal Transmission System is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 259 substations and other transmission facilities that are located in Washington, Oregon, Idaho, and portions of Montana, Wyoming, and northern California. The Federal Transmission System includes a main-grid network for service within the Pacific Northwest, and approximately 80 percent of the northern portion (north of California and Nevada) of the combined Southern Intertie, the primary bulk transmission link between the Pacific Northwest and the Pacific Southwest. The Southern Intertie consists of three high voltage Alternating Current ("AC") transmission lines and one Direct Current ("DC") transmission line and associated facilities that interconnect the electric systems of the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4,800 megawatts of capacity, and in the south to north direction is 3,675 megawatts of capacity. The rated transfer capability of the DC line in the south to north direction is 3,100 megawatts, and in the north to south direction is 3,220 megawatts.

The Federal Transmission System is used to deliver federal and non-federal power between resources and loads within the network, and to import and export power from and to adjacent regions. Bonneville's Transmission Services provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Services; entities that buy and sell non-federal power in the Region such as Regional IOUs, Preference Customers, extra Regional IOUs, independent power producers, aggregators, and power marketers; in-Region purchasers of Federal System power such as Preference Customers and DSIs; and generators, power marketers, and utilities that seek to transmit power into, out of, or through the Region.

Bonneville constructed the Federal Transmission System and is responsible for its operation, maintenance, and expansion to maintain electrical stability and reliability. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by internal, Regional, and national reliability practices. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005" for a discussion of statutory provisions relating to reliability. Bonneville continually monitors the system and evaluates cost-effective reinforcements needed to maintain electrical stability and reliability of the system on a long-term planning basis. A number of conditions, actions, and events could affect the operating transfer capability and diminish the capacity of the system. For example, operating conditions such as weather, system outages, wildfire and other natural disasters, and changes in generation and load patterns may reduce the reliability transfer capability of the transmission system in some locations and limit the capacity of the system to meet the needs of the system's users, including Bonneville's Power Services. To assure that the system is adequate to meet transmission needs, Transmission Services evaluates system performance to determine whether or not to make transmission infrastructure investments.

Bonneville focuses its transmission infrastructure efforts on transmission projects, such as the Project, needed to maintain reliability and new transmission projects that will provide additional, long-term firm transmission service for entities seeking new transmission service in the Region. In recent years, many of the requests for new transmission service have been submitted by customers developing new power generation projects, primarily wind and solar generation, both inside and outside the Region. As reflected in the Final 2024-2025 Rates, Bonneville expects to make transmission system investments in Fiscal Years 2024 through 2033 averaging approximately $544 million annually. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program" and "—Bonneville's Non-Federal Debt." In addition to the investments reflected in the Final 2024-2025 Rates, Bonneville recently announced it is moving forward with over $2 billion in electricity grid improvement investments expected to occur through Fiscal Year 2032 referred to as the "Evolving Grid Projects," that will significantly increase the capacity and reliability of the Pacific Northwest grid and its ability to integrate new energy sources. The Evolving Grid Projects are a group of 10 strategic capital projects needed across Bonneville's service territory to eliminate chokepoints and enable renewable generation projects access to Bonneville's Transmission system and neighboring states utilities to market their production. Projects will increase transmission capacity by up to 6 gigawatts, enough to power about 4.5 million homes and help meet growing demand for more affordable clean power.

If a customer requests to interconnect a new power generation project to the Federal Transmission System, Bonneville uses a process to analyze the request to determine whether and to what extent it needs to construct additional facilities to accommodate the request. In Fiscal Year 2023, Bonneville started a proceeding to improve the efficiency of this process and continues to develop revised business practices. When Bonneville determines that additional facilities need to be constructed to accommodate the request, Bonneville may seek advance funding of its transmission costs for the necessary investments from the customer seeking the interconnection. If the necessary facilities are integrated into Bonneville's network, Bonneville returns to the customer the amounts it advanced for construction of the new facilities (plus interest earned on outstanding balances) in the form of (i) credits against the customer's monthly bills for firm transmission service, or (ii) in some cases, cash payments to the generator or its assigns. The transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were $20 million in Fiscal Year 2023. Bonneville estimates that the transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments will be $20 million in Fiscal Year 2024 and approximately $29 million in Fiscal Year 2025.

Where applicable and in a manner consistent with Bonneville's Tariff, Bonneville may apply the "or" test to recover new transmission facility costs. Under the "or" test, Bonneville compares the "incremental cost" rate for transmission service to Bonneville's embedded cost rate, and charges the requesting customer the higher of the two rates. The application of the "or" test generally protects all other customers from costs they would otherwise bear due to the integration costs of the new facilities.

Bonneville studies and upgrades the Federal Transmission System to meet the Region's emerging commercial needs for expanded transmission service under its Tariff. For Network Integration service requests, Bonneville generally employs a cluster approach wherein it aggregates pending requests for transmission service in order to study and otherwise evaluate the new transmission facilities that it would have to construct to provide that service. Bonneville employs this process to help ensure that it will accurately identify plans of service for serving new requests, recover the costs of any new transmission facilities that are constructed, and avoid stranded transmission investments.

Bonneville's transmission system investment plan is subject to change. Bonneville is unable to predict the cost of new investments for the integration of new generation or to meet customers' new transmission service requests, the amount of transmission that customers will actually commit to, or the extent to which Bonneville will fund such investments through customer advances of funds, borrowing from the United States Treasury, or Non-Federal Debt (that relates to various arrangements to meet Bonneville's capital program which involve debt issued by third parties, the repayment of which is secured by Bonneville financial commitments), such as lease-purchases. For a discussion of the applicability of FERC's cost allocation methodology under Order 1000 (as hereinafter defined), see "—Bonneville's Participation in Regional Transmission Planning."

Federal Transmission System Management for Fire Hazard

Operating the Federal Transmission System poses various risks, including the risk of fire hazard that could result in widespread electric power outages, property damage, personal injury, or death. Bonneville has implemented and employs an integrated vegetation management program that is compliant with the North American Electric Reliability Corporation Standard FAC-003 to help ensure that its transmission lines remain free and clear of brush and trees and that trees and vegetation are a safe clearance distance so that vegetation will not come into contact with Bonneville's transmission lines under any operating conditions. Bonneville performs regularly scheduled vegetation inspections to help ensure the proper height and clearance condition through the use of helicopter patrols with light detection and ranging ("LIDAR") technology to measure the distance between transmission lines and vegetation and through foot patrol by transmission line maintenance crews. Bonneville is recognized as a right-of-way steward utility by the Right-of Way Stewardship Council, which is an accreditation program that establishes standards for responsible right-of-way vegetation management and promotes best practices for maintaining power system reliability and addressing ecological concerns.

In the spring of 2020, Transmission Services released its original Wildfire Mitigation Plan to prevent Bonneville transmission lines and other assets from sparking wildfires, and to protect Bonneville lines and assets from the threat of wildfires. The Wildfire Mitigation Plan was updated in 2021 to add a Public Safety Power Shutoff procedure (the "PSPS"). The PSPS is proactive de-energization of transmission lines and facilities due to extreme weather (i.e., high winds) and other environmental conditions (i.e., low relative humidity and extremely dry fuels) designed to further protect homes, businesses, property and emergency responders from the devastating effects of wildfires.

In September 2020, the Region's typical hot and dry August weather conditions were very quickly followed by a rare, early September dry wind storm with gusts as high as 70 miles per hour, creating a scenario for the extreme wildfire activity witnessed across Bonneville's service territory. Transmission equipment in seven of Bonneville's 13 transmission maintenance districts were impacted by the wildfires. While the majority of Bonneville's response was centered in northeastern Washington State and the Eugene and Salem, Oregon areas of its service territory, field crews from ten Bonneville districts assessed, monitored and worked with dispatch to de-energize and re-energize lines in response to the needs of customers and fire fighters.

In all, Bonneville, at some point, had 38 transmission lines out of service due to the wildfires. Some outages were due to wildfire damage. Others were removed from service so fire fighters could work on or near Bonneville rights-of-way, or to allow Bonneville crews to safely work on the transmission lines.

One of the wildfires, called the Holiday Farm Fire ("HFF"), resulted in claims for damage against the United States Government. To date, Bonneville has received approximately 2,000 perfected administrative tort claims under the Federal Tort Claims Act related to the HFF totaling approximately $2 billion in the aggregate. These claims resulted in three separate suits filed in January and February of 2024 in the U.S. District Court of Oregon. Tort claims must be brought against the United States Government under the Federal Tort Claims Act. All settlements or court judgments from tort claims are paid by the United States Judgment Fund, not the Bonneville Fund. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Limitations on Suits against Bonneville."

On December 12, 2023, the U.S Department of Justice was served with an inverse condemnation claim related to the same wildfire event. The complaint revolves around the theory that the HFF resulted in a taking of plaintiffs' property without just compensation and is therefore compensable under the 5th Amendment of the United States Constitution. Bonneville is unable to predict whether any settlements or judgments arising from this suit would be paid from the United States Judgment Fund or the Bonneville Fund. For more details related to these claims, see "BONNEVILLE LITIGATION—Holiday Farm Fire Litigation."

FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services

In general, the thrust of regulatory changes in the 1990s, both by Congress and FERC, has been to require transmission owners to provide open transmission access to their transmission systems on terms and conditions that do not unduly discriminate in favor of the transmission owner's own power marketing function. EPA-1992 amended sections 211 and 212 of the FPA to authorize FERC to order a "transmitting utility" to provide access to its transmission system at rates and upon terms and conditions that are just and reasonable, and not unduly discriminatory or preferential.

While Bonneville is not generally subject to the FPA, Bonneville is a "transmitting utility" under EPA-1992. Therefore, FERC may order Bonneville to provide others with transmission access over the Federal Transmission System facilities and set the terms and conditions for such FERC-ordered transmission service. However, the transmission rates for FERC-ordered transmission under EPA-1992 are governed only by Bonneville's other applicable laws, except that no such rate shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by FERC. Based on the legislative history of the provisions of EPA-1992 applicable to Bonneville, Bonneville's General Counsel is of the opinion that Bonneville's rates for FERC-ordered transmission services under sections 211 and 212 are to be established by Bonneville, rather than by FERC, and are subject to FERC confirmation and approval through the same process and using the same statutory requirements of the Northwest Power Act as are otherwise applicable to Bonneville's transmission rates. In addition, with respect to Bonneville's ability to recover its transmission costs through its transmission rates, it is the opinion of Bonneville's General Counsel that the EPA-2005 provisions relating to Bonneville's transmission rates would not adversely affect Bonneville's authority and obligation to recover in full the costs of providing transmission service through its transmission rates. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

In 1996, FERC issued Order 888 to promote competition in wholesale power markets. Among other things, Order 888 established a *pro forma* tariff providing the terms and conditions for non-discriminatory open access transmission service, and required all public utilities (the utilities subject to FERC regulation, which does not include government entities such as Bonneville) to adopt the tariff. Order 888 also included a reciprocity provision under which jurisdictional utilities must grant open access transmission services to non-jurisdictional (i.e., unregulated) utilities if the non-jurisdictional utility offers open access in return. FERC issued "Order 890" in February 2007, which further supported Order 888's aims, emphasizing increased transmission access and transparency and promotion of transmission utilization. Bonneville is a non-jurisdictional utility.

EPA-2005 authorizes FERC to require an "unregulated transmitting utility" (a term that includes Bonneville) to provide transmission services to others (i) at rates that are comparable to those that the utility charges itself, and (ii) on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Energy Policy Act of 2005."

Although Bonneville is a non-jurisdictional utility and is not subject to FERC Orders 888 and 890, since 1996, Bonneville has maintained terms and conditions for a non-discriminatory open access transmission tariff that is modeled after FERC's *pro forma* tariff. Bonneville follows the procedures in Section 212(i)(2)(A) of the FPA to make changes to the tariff. Section 212(i)(2)(A), added to the FPA by EPA-1992, provides the Administrator with the option to initiate a regional hearing to adopt transmission terms and conditions of general applicability. The regional hearing largely follows Bonneville's rate case procedures (e.g., opportunities to present oral and written views on the record). The Administrator may also use these procedures for FERC ordered transmission services under EPA-1992.

FERC issued Order 889 in 1996 and Order 717 in 2008. Each order sets forth FERC's Standards of Conduct ("SOC") for jurisdictional transmission providers that have a power marketing affiliate or function. In general, these SOC are intended to assure that wholesale power marketers that are affiliated with a transmission provider do not obtain unfair market advantage by having preferential access to information regarding the transmission provider's transmission operations. Although Bonneville is a non-jurisdictional utility and is not subject to Orders 889 and 717, Bonneville has adopted and follows an SOC policy.

General - Bonneville's Transmission and Ancillary and Control Area Services Rates

Under the Northwest Power Act, Bonneville's Transmission Services rates are set in accordance with sound business principles to recover the costs associated with the transmission of electric power over the Federal System transmission facilities, including amortization of the federal investment in the Federal Transmission System over a reasonable number of years, and other costs and expenses during the rate period. FERC confirms and approves Bonneville's transmission rates after a finding that such rates recover Bonneville's costs during the rate period, and are sufficient to make full and timely payments to the United States Treasury, and, as to Transmission Services rates, equitably allocate the costs of the Federal Transmission System between federal and non-federal power utilizing the system.

Bonneville's Transmission Services rate schedules also include rates for a number of ancillary and control area services. Power Services provides generation inputs, a portion of the available capacity and energy from the Federal System to enable Transmission Services to provide ancillary and control area services. Transmission Services, which purchases generation inputs from Power Services, sets ancillary and control area service rates that recover the generation inputs costs.

The Final 2024-2025 Rates for Transmission Services reflect no change from the average rates in effect in the prior rate period. The Final 2024-2025 Rates for Transmission Services continue the availability of the RDC, which has triggered for application to Fiscal Year 2024 Transmission Services rates. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments."

Transmission Services' Largest Customers

The following table lists Transmission Services' ten largest customers in terms of their percentage contribution to Transmission Services' overall sales revenue in Fiscal Year 2023. The table also notes the type of entity for each customer.

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Transmission Services' Ten Largest Customers By Sales[(1)]
(Percentage of Transmission Services' Sales Revenue in Fiscal Year 2023)

Customer Name (Class)	Approximate % of Sales
Puget Sound Energy Inc. (Regional IOU)	14%
PacifiCorp (Regional IOU)	9%
Portland General Electric Company (Regional IOU)	9%
Powerex Corp. (Power Marketer)	9%
Avangrid Renewables, LLC (Wind Developer)	5%
City of Seattle, City Light Dept. (Preference Customer)	5%
Snohomish County PUD No. 1 (Preference Customer)	5%
Morgan Stanley Capital Group Inc. (Power Marketer)	3%
Pacific Northwest Generating Cooperative (Preference Customer)	3%
Umatilla Electric Cooperative (Preference Customer)	3%

(1) Excludes inter-business line transactions between Power Services and Transmission Services. In support of its power marketing activities, Power Services obtains large amounts of transmission and related services from Transmission Services.

Bonneville's Participation in Regional Transmission Planning

Bonneville has long participated in Regional transmission planning, transitioning from its membership in the Regional planning organization, "ColumbiaGrid," to "NorthernGrid," which was implemented in 2020. NorthernGrid, like ColumbiaGrid, is not a Regional Transmission Organization ("RTO") under FERC policies. With 13 member utilities across the Northwest and some Rocky Mountain states, NorthernGrid includes a broader membership base than ColumbiaGrid's membership of eight Pacific Northwest utilities. The nature of the coordinated planning that occurs through Bonneville's participation in NorthernGrid is similar to the planning activities that Bonneville participated in through its membership in ColumbiaGrid. In addition to NorthernGrid's coordinated planning, Bonneville continues to explore opportunities to address regional and inter-regional transmission planning needs by engaging in Western Power Pool's Western Transmission Expansion Coalition ("WestTEC") initiative to explore west-wide transmission planning. WestTEC is a voluntary and inclusion planning effort that does not address cost allocation.

In Order 890, FERC provided direction regarding principles for open, coordinated transmission planning on a Regional level, and as a member of ColumbiaGrid for more than a decade Bonneville participated in a Regional transmission planning process that substantially conformed to the transmission planning requirements in Order 890. Subsequent to its "Order 890" reforms, FERC provided transmission planning and cost allocation direction in its "Order 1000." Order 1000 requires jurisdictional utilities to participate in certain Regional and interregional transmission planning processes and cost allocation methodologies for transmission projects. Cost allocation involves the mandatory (non-voluntary) contribution by utilities to the cost of the related transmission projects. Although Order 1000 does not apply to non-jurisdictional utilities such as Bonneville, FERC encourages non-jurisdictional utilities to participate by requiring compliance in order to obtain reciprocity and by indicating that it might exercise its authority under FPA section 211A to require such utilities to comply if they do not do so voluntarily.

After FERC issued Order 1000, Bonneville remained a member of ColumbiaGrid and continued to participate in ColumbiaGrid Regional planning but decided not to participate in the Order 1000 reforms. As a member of NorthernGrid, Bonneville's participation with respect to the Order 1000 requirements remains the same. That is, Bonneville participates in coordinated Regional planning without being subject to mandatory cost allocation, and it is not able to impose mandatory cost allocation of its proposed projects on other participating utilities. Bonneville amended its open access transmission tariff to reflect its participation in NorthernGrid as part of the Fiscal Year 2022 Terms and Conditions Tariff Proceeding. Bonneville does not intend to revisit its decision regarding its participation in the Order 1000 reforms at this time. In April 2022, FERC initiated a formal rulemaking proceeding to consider reforms to regional transmission planning and cost allocation processes. The proposed reforms are not directed at non-jurisdictional utilities. FERC has not issued a final rule, but Bonneville continues to follow the rulemaking process to evaluate for any potential impacts to Bonneville's on-going participation in coordinated Regional planning without being subject to mandatory cost allocation.

MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards

Bonneville is required to periodically review and, as needed, to revise rates for power sold and transmission services provided in order to produce revenues that recover Bonneville's costs, including its payments to the United States Treasury. The Northwest Power Act contains numerous ratemaking directives and incorporates the provisions of other Bonneville organic statutes, including the Bonneville Project Act, the Transmission System Act and the Flood Control Act of 1944. The Transmission System Act requires, among other things, that Bonneville establish its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment to the United States Treasury. Substantially the same requirements are set forth in the Flood Control Act.

Bonneville Ratemaking Procedures

The Northwest Power Act contains specific ratemaking procedures used to develop a full and complete record supporting a proposal for revised rates. The procedures include publication of the proposed rate(s), together with a statement of justification and reasons in support of such rate(s), in the Federal Register and a hearing before a hearing officer. The hearing provides an opportunity for parties to present material and to refute or rebut material submitted by Bonneville or other parties and also provides a reasonable opportunity for cross-examination, as permitted by the hearing officer. Upon the conclusion of the hearing, the hearing officer certifies a formal hearing record (including hearing transcripts, exhibits, and such other materials and information as have been submitted during the hearing) to the Bonneville Administrator. This record provides the basis for the Administrator's final decision, which must include a full and complete justification in support of the proposed rate(s).

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

Rates established by Bonneville under the Northwest Power Act may become effective only upon confirmation and approval by FERC, although FERC may grant interim approval of Bonneville's proposed rates pending FERC's final confirmation and approval.

Under the Northwest Power Act, FERC's review of Bonneville's power and transmission rates involves three standards. These standards require FERC to confirm and approve the rates based on findings that such rates: (i) are sufficient to assure repayment of the federal investment in the Federal System over a reasonable number of years after first meeting Bonneville's other costs; (ii) are based on Bonneville's total system costs; and (iii) insofar as transmission rates are concerned, equitably allocate the costs of the Federal Transmission System between federal and non-federal power utilizing such system. FERC does not, however, review Bonneville's rate design or cost allocation for purposes other than equitable allocation of transmission costs.

FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a rate in lieu of a proposed rate that FERC finds does not meet the applicable standards. In the opinion of Bonneville's General Counsel, if FERC were to reject a proposed Bonneville rate, FERC would be limited to remanding the proposed rate to Bonneville for further proceedings as Bonneville deems appropriate. On remand, Bonneville would reformulate the proposed rate to comply with the FERC order. If FERC has previously given the rate interim approval, Bonneville may be required to refund the difference between the interim rate charged and any final FERC-approved rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

For a discussion of FERC's rate review and regulation related to transmission access and rates, see "TRANSMISSION SERVICES—FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services," and "—Energy Policy Act of 2005."

Judicial Review of Federal Energy Regulatory Commission Final Decisions

FERC's final approval of a proposed Bonneville rate under the Northwest Power Act is a final action subject to direct, exclusive review by the Ninth Circuit Court, if challenged. Suits challenging final actions must be filed within 90 days of the time such action is deemed final. The record upon review by the court is limited to the administrative record compiled in accordance with the Northwest Power Act.

Unlike FERC, the court reviews all of Bonneville's ratemaking for conformance with all Northwest Power Act standards, including those ratemaking standards incorporated by reference in the Northwest Power Act. In the opinion of Bonneville's General Counsel, the court lacks the authority to establish a Bonneville rate. Upon review, the court may either affirm or remand a rate to FERC or Bonneville, as appropriate. On remand, Bonneville would reformulate the remanded rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville may be subject to refund obligations if the reformulated rate were lower than the remanded rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Power Customer Classes

The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (i) to Preference Customers, regional federal agencies, and investor-owned utilities; (ii) to DSIs; and (iii) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for firm power sold to these respective customer classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

Surplus Energy

Bonneville is authorized to sell power that is surplus to meeting Bonneville's regional firm power sales obligation and seasonal surplus power both within and outside the Pacific Northwest. Many of these sales are to purchasers outside the region, primarily to California under short-term power sales that allow for flexible prices, or under long-term contract rates.

Limitations on Suits against Bonneville

Suits challenging Bonneville's actions or inaction may only be brought pursuant to certain federal statutes that waive sovereign immunity. These statutes specify the types of actions, remedies available, procedures to be followed, and the proper forum. Any tort claims, including any tort claims related to the September 2020 wildfires (see "TRANSMISSION SERVICES—Federal Transmission System Management for Fire Hazard"), must be brought against the United States Government under the Federal Tort Claims Act. All settlements or court judgments from tort claims are paid by the Judgment Fund, not the Bonneville Fund. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville is a judgment for money damages. See "BONNEVILLE LITIGATION" for information regarding pending litigation seeking to compel or restrain action by Bonneville.

Laws Relating to Environmental Protection

Bonneville must comply with a host of environmental laws to prevent and address environmental contamination related to its operations, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") and its state equivalents. Currently, there is one Superfund site (Portland Harbor Superfund Site) and one non-Superfund facility for which Bonneville has been identified by regulatory agencies as being a Potentially Responsible Party ("PRP") for some of the contamination. The United States Department of Justice is representing federal agencies, including Bonneville, in ongoing CERCLA mediation and settlement processes for the Portland Harbor Superfund Site where there are over 150 PRPs; response costs, including remediation and natural resource damage assessments and injuries will ultimately be paid as non-reimbursable expenses from the United States Judgment Fund, not the Bonneville Fund. For the other facility, investigations are still in early stages; even if Bonneville were determined to be liable, the cost associated with cleanup of this site is expected to be less than $3 million.

As a separate and distinct matter, the Corps has its own CERCLA liability and is exercising its Executive Order 12580 cleanup implementation authority at two Corps-operated facilities (Big Cliff Reservoir Former Construction Site and Bradford Island) at Federal System Hydroelectric Projects (Detroit/Big Cliff Dam and Bonneville Dam). The EPA listed Bradford Island as a Superfund site in March 2022. Bonneville does not have direct CERCLA liability at either site and is not potentially responsible for contamination; however, the Corps has applied the power generation share of the joint operation and maintenance expense funds received from Bonneville for Detroit/Big Cliff Dam and Bonneville Dam to the Corps' early stage cleanup at these two sites. In Fiscal Year 2023 and Fiscal Year 2024, Bonneville expects that such costs will be approximately $2 million in the aggregate. In Fiscal Year 2025, Bonneville expects that such costs will be approximately $5.5 million. For additional details regarding Corps costs allocated to power generation at Federal System Hydroelectric Projects, see "POWER SERVICES—Description of the Generation Resources of the Federal System—Federal Hydro-Generation."

Energy Policy Act of 2005

EPA-2005 was enacted by Congress in July 2005. Among other things, EPA-2005 amended the FPA by including new provisions applicable to unregulated utilities' power and transmission marketing. Provisions in EPA-2005 that have had the greatest impact on Bonneville's operations include the following:

(i) EPA-2005 amends the FPA to authorize FERC to require an unregulated transmitting utility (a term that includes Bonneville) to provide transmission services at rates comparable to those the utility charges itself, and on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. See "—Renewable Generation Development and Integration into the Federal Transmission System" for discussion of special tariff provisions related to compensation of non-federal generators (primarily wind generators) for being displaced in oversupply events that were established after FERC exercised its authority under this provision in response to a complaint related to displacement as a result of oversupply events filed by certain customers against Bonneville.

(ii) EPA-2005 authorizes the Secretary of Energy or, upon designation by the Secretary, the administrator of a power marketing administration ("PMA") including Bonneville, to transfer control and use of the PMA's transmission system to certain defined entities, including an RTO, independent system operator, or any other transmission organization approved by FERC for operation of transmission facilities. The section further provides that the contract, agreement, or arrangement by which control and use is transferred must include provisions that ensure recovery of all of the costs and expenses of the PMA related to the transmission facilities subject to the transfer, consistency with existing contracts and third-party financing arrangements, and consistency with the statutory authorities, obligations, and limitations of the PMA. See "TRANSMISSION SERVICES—Bonneville's Participation in Regional Transmission Planning."

(iii) EPA-2005 grants FERC limited authority to order refunds in the case of certain energy sales by non-jurisdictional utilities such as Bonneville. The refund authority is limited to sales of 31 days or less made through an organized market in which the rates for the sale are established by a FERC-approved tariff. The refund authority applies to Bonneville only if the rate for the sale by Bonneville is unjust and unreasonable and is higher than the highest just and reasonable rate charged by any other entity for a sale in the same geographic market for the same or most nearly comparable time period.

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue mandatory reliability standards that cover all users, owners, and operators of the bulk power system. WECC acts for the North American Electric Reliability Corporation ("NERC"), which is the ERO established by FERC. The mandatory reliability standards apply to Bonneville, but EPA-2005 expressly states that neither the ERO nor FERC is authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. Monetary penalties for violation of the standards may be assessed by the ERO and approved by FERC, or assessed by FERC itself. However, neither the ERO nor FERC has jurisdiction to assess a monetary penalty against the United States, including Bonneville. Thus, while Bonneville must still comply with the mandatory reliability standards, it does not face penalties, monetary or otherwise, for any violations.

Other Applicable Laws

Many statutes, regulations, and policies are or may become applicable to Bonneville, several of which could affect Bonneville's operations and finances. Bonneville cannot predict with certainty the ultimate effect such statutes, regulations or policies could have on its finances.

Columbia River Treaty

Bonneville and the Corps have been designated by executive order to act as the "United States Entity," which, in conjunction with a Canadian counterpart, the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River basin for the purposes of power generation and flood control. Pursuant to the Treaty, Canada constructed the Mica, Arrow and Duncan hydroelectric projects in Canada to provide 15.5 MAF of storage that allows for regulation of streamflow, which in turn increases power production and provides flood risk management for both the United States and Canada.

For power production, regulation of streamflow by the Canadian reservoirs enables certain hydroelectric projects, some of which are part of the Federal System, that are located in the United States on or near the Columbia River to produce more usable energy than otherwise would occur in the absence of Canadian storage. This increase in usable energy is termed the "downstream power benefits." The Treaty specifies that the downstream power benefits be shared equally between the two countries. Canada's portion of the downstream power benefits is known as the "Canadian Entitlement."

The Treaty specifies that the Canadian Entitlement be delivered to Canada at a point along the United States-Canada border near Oliver, British Columbia unless the United States Entity and the Canadian Entity agree to other arrangements. In the late 1990s, the United States Entity and Canadian Entity reached such an agreement through 2024, and as a result the United States Entity does not have to build a transmission line to assure delivery to the point referred to in the Treaty during the term of the agreement.

The United States Entity and Canadian Entity have previously consulted on terms for possible disposal of portions of the Canadian Entitlement in the United States. Direct disposal of the Canadian Entitlement in the United States was authorized through 2024 by the executive branches of the United States and Canadian governments through an exchange of diplomatic notes, which occurred in 1999.

Under the Treaty, Canadian storage operates to meet planned Regional firm loads during low water conditions providing additional water downstream for hydro-generation to help meet the loads of Bonneville and certain other Regional utilities. This Treaty operation is incorporated into Bonneville's estimate of the firm power of the Federal System under Low Water Flows/Firm Water. See "POWER SERVICES—Description of the Generation Resources of the Federal System."

For flood risk management, the storage in Canada is generally drafted through the fall and winter to create storage space and refilled during the spring/summer runoff to manage floods. The Treaty provides for assured flood risk management operations in Canadian reservoirs until September 2024 to reduce flood impacts to communities in both Canada and the United States. In September 2024, the Treaty shifts to certain modified procedures for flood risk management operations. The Entities and their governments will be discussing how to coordinate and implement this change.

The Treaty has no expiration date and thus could continue indefinitely. The Treaty does, however, allow either the United States or Canada to elect to terminate the Treaty (except for primarily its flood risk management provisions) at any time after September 2024, but only if at least ten years' written notice has been provided. No such notice has been issued by either country.

On December 13, 2013, the United States Entity sent a final Regional Recommendation concerning the post-2024 future of the Treaty to the United States Department of State. In general, the Regional Recommendation proposed to modernize the Treaty to more fairly reflect the distribution of operational benefits between the United States and Canada; to ensure that flood risk management, an economical and reliable power supply, and other key river uses are preserved; and to address key ecosystem functions in a way that complements the significant investments made to protect fish and wildlife over the past three decades. The final recommendation submits that the Pacific Northwest Region and the United States would benefit from modernization of the Treaty post-2024.

In 2015, the United States government concluded a federal interagency review on the question of the post-2024 future of the Treaty. This review was conducted under the general direction of the National Security Council on behalf of the President of the United States and was coordinated and overseen by the United States Department of State. The United States Department of State then named a lead negotiator and began working with the United States Entity and other federal agencies toward completing the official authorization which would allow the United States government to negotiate with Canada. In late 2016, the United States Department of State approved this negotiation authorization. The United States and Canada began negotiations to modernize the Columbia River Treaty regime in May 2018. The nineteenth round of negotiations was held in October 2023. During this round, the United States and Canada made progress on the operational aspects of the negotiations, such as post-2024 flood risk management, Canada's desire for more operational flexibility, hydropower coordination, establishing mechanisms for incorporating tribal and indigenous input, and mechanisms for achieving ecosystem objectives. The main remaining issue on which the countries need to reach agreement is the compensation provided to Canada under the Treaty. Discussions of that issue have been continuing among a small group of government officials.

Proposals for Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of Bonneville's current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in or submitted to Congress have included privatizing all or part of the federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at federal hydroelectric projects, studying the breaching or removal of certain federally-owned dams of the Federal System, placing caps on Bonneville's authority to incur certain types of capitalized costs, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates, and limiting Bonneville's ability to incur new Non-Federal Debt.

Previous administrations have, from time to time, included in their President's Budget Requests to Congress, proposals to sell assets owned and operated by the PMAs, including those of the Southwestern Power Administration, Western Area Power Administration, and Bonneville Power Administration and to authorize the PMAs to charge rates comparable to those charged by for-profit, investor-owned utilities, rather than being limited to cost-based rates, for electricity. Bonneville is unable to predict whether similar proposals or any other proposal with respect to Bonneville will be included in future President's Budget Requests to Congress or the effects any such proposal would have on Bonneville or its Non-Federal Debt if enacted into law.

Federal Debt Ceiling

In order to fund its general operations, the United States relies on current receipts and the proceeds of debt obligations issued by the United States Treasury. In recent years, the United States has narrowly avoided a situation where it would be unable to fund all of its operations because it reached the Congressionally-established debt ceiling. A future failure to raise the United States Treasury debt ceiling could result in default by the United States and have adverse implications on all funds held by the United States Treasury, including the Bonneville Fund. It is possible that actions taken or not taken by the United States Treasury or others at such times could materially affect Bonneville's operations and financial condition, including, among other things, restricting Bonneville's ability to borrow either short- or long-term from the United States Treasury and Bonneville's access to the Bonneville Fund to meet its cash payment obligations, including under the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements. On June 3, 2023, President Biden signed legislation suspending the debt ceiling until January 1, 2025.

Government Shutdown and Effects on Bonneville

From time to time, including during Fiscal Year 2019, Congress has failed to timely enact federal appropriations legislation which has resulted in the shutdown of many of the Federal government's operations. Bonneville's funding and the operation of the Federal System are not affected by the lack of enactment of federal budget legislation.

Direction or Guidance from other Federal Agencies

Bonneville is part of the federal government. It is subject to direction or guidance in a number of respects from the OMB, DOE, FERC, the United States Treasury and other federal agencies. Bonneville is frequently the subject of, or would otherwise be affected by, various executive and administrative proposals. Bonneville is unable to predict the content of future proposals; however, it is possible that such proposals could materially affect Bonneville's operations and financial condition.

Environmental, Social and Governance Considerations

As described elsewhere in this Appendix A, Bonneville was created by an act of Congress in 1937 and is one of four regional federal power marketing agencies within the DOE. Bonneville markets wholesale electric power from 31 federally-owned hydroelectric dams in the Pacific Northwest, one nonfederal nuclear plant, and several small nonfederal power plants. Bonneville provides about 28 percent of the electric power generated in the Pacific Northwest. Its resources, primarily hydroelectric, make Bonneville's power nearly carbon free.

Bonneville's statutory authorities from its enabling legislation as well as other statutes that apply to Bonneville actions (including the ESA, NEPA, and CERCLA) govern its operations and require commitments related to the considerations being discussed in this section. See "GENERAL," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—The National Environmental Policy Act and the Endangered Species Act," and "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Laws Relating to Environmental Protection."

Sustainability at Bonneville

Bonneville is committed to public service and seeks to make its decisions in a manner that provides opportunities for input from all stakeholders. In its vision statement, Bonneville dedicates itself to providing high system reliability, low rates consistent with sound business principles, environmental stewardship and accountability. Bonneville's Sustainability Leadership Committee, made up of executive leadership from across the agency, ensures communication, coordination, transparency and strategic alignment of sustainability initiatives. Four workgroups operate under the Sustainability Leadership Committee – focused on fleet electrification, net-zero buildings, pollinators, and sustainable materials – provide subject matter expertise and sustainability project ideas.

Bonneville works towards resource efficient policies and practices that deliver long-term, quantifiable value for Bonneville and its stakeholders. Bonneville's Sustainability Office fosters employee engagement and intra-agency coordination while addressing federal mandates on sustainability and climate resilience. The Sustainability Office supports the strategic goals included in the 2024–2028 Strategic Plan by conserving resources, investing in people, modernizing business processes, increasing operational efficiencies and lengthening the lifespan of assets which ultimately leads to strengthened financial health and competitiveness.

Bonneville makes sustainability performance metrics available on an annual basis. These reports provide transparency on Bonneville's fugitive emissions; electricity, water, and fossil fuel use; waste generation and recovery and more. Bonneville has won nearly two dozen awards for its achievements in reducing its environmental footprint from operations, including multiple regional and national Federal Green Challenge awards, an effort under the Environmental Protection Agency ("EPA") Sustainable Materials Management Program that challenges other federal agencies to lead by example in reducing the federal government's environmental impact, and DOE Sustainability awards. Bonneville has constructed several Leadership in Energy and Environmental Design (LEED)-certified buildings, including the Maintenance Headquarters Building at Bonneville's Ross Complex. All of Bonneville's new buildings are built to the most up-to-date building codes, which often include energy saving measures.

Energy Efficiency

In Fiscal Year 2023, Bonneville issued a draft 2022-2027 Energy Efficiency Action Plan based on its 2022 Resource Program and the Council's Eighth Power Plan. The Council's plan helps guide energy and conservation development in the Region, sets forth guidance for Bonneville regarding conservation and developing generating resources to meet Bonneville's Regional load obligations, addresses risks and uncertainties for the Region's electricity future, and seeks a resource strategy that minimizes the expected cost of the Regional power system over the ensuing 20 years. Consistent with the Council's analysis, achieving the Council's energy efficiency goal helps Bonneville and other utilities in the Region manage future Regional load growth and minimize reliance on development of other carbon-emitting resources to meet future demand, and will help address future Regional peaking capacity needs. For more details on Bonneville's 2022-2027 Energy Efficiency Action Plan, Bonneville's 2022 Resource Program, and the Council's plan, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies."

While fulfilling its mission to deliver power to meet the Region's power needs, Bonneville promotes energy efficiency, renewable resources, and new technologies.

Environment, Fish and Wildlife

Bonneville implements an Environment, Fish, and Wildlife Program to mitigate for the impacts of the development and operation of the federal dams on fish and wildlife and their habitat, and implements a large environmental compliance program to ensure Bonneville's activities related to the federal power and transmission systems with a host of federal laws. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife." Bonneville, the Corps, and Reclamation manage a complex operation that balances the many uses of the Columbia River system, including power production, flood control, irrigation, navigation, and recreation with river flows and fish passage.

Bonneville develops and implements policies and strategies for meeting Bonneville's environmental, fish and wildlife, and cultural resource responsibilities through cost-effective solutions; ensures all Bonneville business functions comply with established environmental laws, rules and legal mandates in the most collaborative and cost-effective manner possible; and carries out regional coordination of agency environmental activities through collaborative relationships with other federal agencies; American Indian tribes; the Council; Bonneville customers; state and local governments; congressional delegations and committees; natural resource groups; and the public.

Protection and Preservation of Cultural Resources

Consistent with the National Historic Preservation Act, Bonneville manages cultural resource compliance activities in consultation with affected Tribes, State Historical Preservation Offices, Tribal Historical Preservation Offices, other federal and state land management agencies, the federal Advisory Council on Historic Preservation and interested members of the public, as appropriate. Bonneville's help ensures cultural resources are considered during the planning and implementation of Bonneville's activities.

Vegetation Management and Fire Prevention Program

Bonneville’s vegetation management program relies on a cohesive group of experts who manage the vegetation on and around Bonneville's 15,000 miles of transmission lines on 8,500 miles of rights-of-way and facilities, such as substations, switchyards and microwave/radio sites in the Pacific Northwest. Bonneville employs natural resource specialists and foresters who use ground patrols and LIDAR to identify trees and vegetation within and adjacent to Bonneville’s rights-of-way that could potentially fall and damage Bonneville's transmission equipment or facilities, or otherwise interfere with grid reliability.

Additionally, a regular integrated vegetation maintenance cycle and clearing on easements helps keep transmission corridors clear of fuel for wildfires. To perform this work, Bonneville contracts vegetation clearing crews that comply with all applicable laws and regulations pertaining to fire prevention. They carry firefighting equipment, use chainsaws with spark arresters and provide a fire watcher when necessary. The contract crews manage the debris to minimize fire hazards by cutting, lopping and scattering branches, which disperses the potential fuel and maximizes the contact with the ground to promote decomposition. The natural resource specialists developing the annual work plan consider the risk of fire and the environmental restrictions associated with threatened and endangered species. See “TRANSMISSION SERVICES—Federal Transmission System Management for Fire Hazard.”

Monitoring and Mitigating Climate Change Impacts

Federal, regional, state, and international initiatives have been proposed or adopted to address global climate change by monitoring and reducing greenhouse gas emissions, by encouraging renewable energy development, and by implementing other measures. Bonneville cannot predict whether or when new laws and regulations or proposed initiatives would take effect in a manner that would affect Bonneville.

Certain states have initiated regulatory actions designed to regulate greenhouse gas emissions in the electricity industry. For instance, the State of California initiated a cap and trade program that became active in 2013. Bonneville sells substantial amounts of surplus electric power to parties within the State of California. The State of Washington passed the Clean Energy Transformation Act (“CETA”) in 2019. CETA requires retail utilities in the State of Washington to eliminate the cost of coal plants from their rates by January of 2026, to become carbon neutral by 2030, and to become carbon free by 2045. Washington also passed, in 2021, a cap and trade law patterned after California’s program. The Washington cap and trade program went into effect on January 1, 2023.

Given the predominance of non-carbon emitting hydro- and nuclear-based generation in the Federal System, to the extent that global climate change initiatives impose controls or costs on carbon-emitting generation, their impact on the cost of the output of the Federal System is anticipated to be minimal. Market purchases represent between 3-12 percent of Bonneville’s annual fuel mix and are the sole source of carbon emissions. While a small amount of these purchases are renewable, the generator that produced the power at the time of transaction is not identified, making carbon-free numbers an estimate based on the state-assigned carbon emissions rate on market purchases. Currently, Bonneville’s system is estimated to be 95 percent carbon-free.

Bonneville believes that carbon-limiting programs will have the effect of increasing demand for Federal System power given the low-carbon attributes of the system. Certain high carbon intensity resources, particularly coal-fired generation, are retiring early and this could potentially extend to natural gas generation. In the future, the Federal System could be an important component of addressing and reducing greenhouse gas emissions as it provides the Pacific Northwest region with a reliable, flexible source of carbon-free generation that can help meet loads and integrate new intermittent renewable resources (like wind and solar).

In addition, Bonneville believes that carbon-limiting proposals are likely to result in more renewable resource development, with accompanying generation integration issues similar to those that Bonneville has seen in the integration of wind generation. To the extent that new regulations and incentives for non-carbon based generation increase the development of new generation facilities, Bonneville could face increased costs for integrating such facilities into the Federal Transmission System. However, Bonneville would be required by law to recover the costs in transmission and related rates. See “—Renewable Generation Development and Integration into the Federal Transmission System.”

Bonneville's 2024-2028 Strategic Plan frames supporting regional carbon reduction among Bonneville's strategic priorities, outlining goals and objectives for Bonneville to address in the coming years. Consistent with Bonneville's statutory obligations, Bonneville will strive to acquire cost-effective carbon-free resources to help meet load growth with clean resources and decrease unspecified power purchases. Bonneville is also exploring forward-thinking ancillary services to support: (i) the integration of new loads and emerging technology; (ii) enable expansion of available transmission for customers; and (iii) aid in the integration and delivery of new, clean resources. See "BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville Financial Operations."

Consistent with President Biden's Executive Order 14057 on catalyzing American clean energy industries and jobs through Federal sustainability and accompanying Federal Sustainability Plan, which outlines an ambitious path to achieve net-zero emissions across Federal operations by 2050, Bonneville is beginning to transition its passenger vehicle fleet to zero emission vehicles and supports the other goals outlined in the plan. In addition, Bonneville is in the process of installing charging stations and supporting infrastructure to enable electric vehicle charging at its facilities.

Bonneville has been studying and monitoring the impacts of climate change on Bonneville's assets and operations for over 15 years. Bonneville, in partnership with its federal partners, the Corps and Reclamation, has funded research to understand the risks, vulnerabilities and resiliency the Federal System faces due to a changing climate. Bonneville is also collaborating with DOE and Oak Ridge National Lab to evaluate the effects of climate change on federal hydropower.

In Fiscal Year 2022, Bonneville's Sustainability Office completed an initial analysis to assess vulnerabilities of several Bonneville assets and critical systems due to climate change. The Sustainability Office continues to refine this analysis and explore avenues to implement mitigation measures and monitor their success.

The physical effects of climate change are likely to affect the generation capability of the Federal System to meet loads given the Federal System's reliance on precipitation and snowpack. In addition, climate change could affect load patterns if space-heating and cooling demands change, and if heat waves become more frequent and severe. Climate change may also affect the timing and type of seasonal precipitation, which may affect how the Federal System is operated. Finally, changes in climate could adversely affect fish and wildlife populations affected by the Federal System, possibly resulting in additional costs. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

In response to observed and projected climate change trends in the region, in 2022 Bonneville decided to update assumptions used in long-term hydrogeneration planning, switching to a more recent subset of streamflows to forecast near-term future generation. Bonneville believes this change will result in a more accurate forecast of the capability of the Federal System to produce power in future years.

In addition to the physical effects of climate change that could affect the generation capability of the Federal System, Bonneville continues to monitor and forecast the potential impacts to load levels related to the electrification of vehicles and aircraft to mitigate for climate change. The states of Oregon, Washington, and California have all recently passed legislation requiring that all new vehicles sold in the states are zero-emitting by 2035. These mandates phase in gradually beginning with model year 2026, requiring that 35% of new passenger vehicle sales are electric vehicles, and increase each year until all vehicles covered by the rule must be zero emissions. As part of its loads and resources studies, Bonneville estimates the amount of load that it will be required to meet under its contracts and incorporates these factors. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Federal System Load/Resource Balance." Bonneville does not expect the electrification of vehicles and aircraft or the use of residential solar panels to have material impacts on load levels until at least 2028.

Diversity and Inclusion in the Bonneville Workforce

Bonneville's 2024-2028 Strategic Plan begins with the goal, "Invest in people," with objectives that target improvements in workplace culture and workforce capabilities. Released in March of 2024, Bonneville's Culture Strategy aligns with the 2024-2028 Strategic Plan and articulates how Bonneville will invest in people and enable the achievement of all other strategic goals. The Culture Strategy is built on a strong foundation through Bonneville's existing focus on safety, leadership behaviors, diversity and inclusion, equal employment opportunity and responsiveness to the changing needs of Bonneville's customers.

Bonneville has invested in diversity and inclusion by dedicating resources and creating the Diversity and Inclusion Office to build an inclusive culture that leverages the power of diversity, using self-awareness and safe dialogue. Additionally, Bonneville has placed a stronger emphasis on civil rights and leveraging the Equal Employment Opportunity office to encourage a workplace that is free from harassment and discrimination. Five-year goals of the Diversity and Inclusion Office are to: (i) increase workforce demographic diversity by recruiting and retaining a highly talented workforce that reflects the communities Bonneville serves; (ii) empower leadership at all levels by engaging the entire workforce to create and sustain a culture of inclusion; and (iii) foster a culture of inclusion by leveraging personal stories to connect with one another through shared purpose, self-awareness and creating opportunities for safe dialogue.

Transparency and Governance

Bonneville is dedicated to public involvement and transparency in all aspects of its operations. Bonneville regularly holds events and public comment periods to update and receive input from stakeholders and the public. Bonneville also provides past and current records of decisions to keep the public informed on Bonneville initiatives, projects, finances and other business updates.

Bonneville engages extensively with customers and regional stakeholders regarding Bonneville's proposed expenditures. The Integrated Program Review ("IPR") allows interested external parties to see and comment on all relevant Federal Columbia River Power System capital and expense spending level estimates in the same forum. The IPR occurs just prior to each rate case and is the public review for the costs that will be recovered through rates the following rate period. Topics covered within the process include Transmission, Federal Hydro, Facilities, Information Technology, Energy Efficiency, Fish and Wildlife, and other programs. Bonneville's wholesale power and transmission rates are established though a formal process described in section 7(i) of the Northwest Power Act. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments."

Preparedness, Cyber, and Physical Security

Areas of increased attention in the electric power industry include managing risks to assure operational continuity and assurance of both cyber security and security of physical assets. In addition to normal storm and wildfire response procedures to maintain the integrity of the Federal Transmission System, Bonneville has a Continuity of Operations program that has coordinated the development and testing of plans, systems and facilities to continue to operate through, or quickly recover from, a major disruption. Bonneville operates redundant system control centers that are geographically separated, one east and one west of the Cascade Mountains, in areas not subject to the same geographic vulnerabilities. In a major disruptive event, either control center will be capable of managing transmission capacity and power sales as well as coordinating power generation operations.

New technical cyber vulnerabilities are discovered in the United States daily. In addition, cyber-attacks have become more sophisticated and increasingly are capable of impacting industrial control systems and components. To face these and other challenges of cyber security, Bonneville is taking several key steps to expand its cyber security capabilities. Bonneville is working on implementation of a program known as Continuous Diagnostics and Mitigation which provides real-time detailed centralized cyber security monitoring of inventory, hardware, software and data as well as vulnerabilities that can be addressed. This is part of a government-wide effort sponsored by the United States Department of Homeland Security's Cybersecurity and Infrastructure Security Agency. Bonneville has permanent, full-time staff in its Office of Cyber Security to perform offensive cyber security research and penetration testing, to gather and analyze intelligence threat information to stay abreast of new vulnerabilities, and to assess exposure and respond accordingly to mitigate threats and share information. Bonneville has also developed alliances within the federal government to deploy intelligent devices to monitor external threats from the Internet and implemented a Cyber Security Operations and Analysis Center to improve Bonneville's capability and situational awareness. Bonneville participates in the joint government-Electric Subsector Coordinating Council as well as other industry groups with a focus on anticipating and mitigating cyber security risks and is subject to the mandatory NERC reliability standards including cyber security standards.

Bonneville continues to enhance its operational security through the implementation and monitoring of a prioritization of real time cyber security controls in pursuit of anomalous activity and offensive cyber security research on operational technology. Bonneville believes that these efforts will help it face the challenge of increasing use of digital devices and increasing threats.

Bonneville's Physical Security Office is responsible for enacting and managing a comprehensive physical security program that is risk based and in compliance with multiple regulations, including DOE orders and applicable North American Electric Reliability Corporation Critical Infrastructure Protection ("NERC-CIP") standards, and United States Department of Homeland Security requirements. The physical security approach by Bonneville strives to meld these various requirements into one sustainable program. This program seeks to incorporate industry best practices where possible and also collaborate with other utilities, power marketing administrations, and industry partners.

The physical protection strategy employed by Bonneville attempts to gain security capabilities to deter, detect, delay, assess, communicate and respond to security-related threats and events. As Bonneville works to physically protect its buildings and facilities, Bonneville started categorizing assets based on mission criticality and then applying security measures which include: physical hardening, contract security officers, physical access control systems, intrusion detection systems, and video assessment and surveillance systems based on the critical nature of the asset.

Another program element adopted by Bonneville includes threat awareness and threat management. Bonneville's Physical Security Office dedicates personnel resources to monitor threat intelligence information, maintain relationships and partnerships with state Fusion Centers, DOE Counter-Intelligence, the Electric Sector Information Sharing and Analysis Center, as well as federal, state and local law enforcement agencies. This internal capability helps Bonneville to remain aware of and adapt to the evolving threat picture.

Physical security policy and program effectiveness are assessed through Bonneville's Security Performance and Assurance Program, security risk assessment processes, Bonneville's annual NERC-CIP certification process, DOE self-assessment reporting for Safeguards and Security topical areas, and Bonneville's Office of Security and Continuity of Operations annual internal self-assessment activities for Safeguards and Security programs. Through these established efforts, the Office of Security and Continuity of Operations is able to monitor Safeguards and Security effectiveness, efficiency, and compliance with DOE and NERC-CIP security related requirements. Additionally, the Office of Security and Continuity of Operations is able to assess the performance of the layers of security and related programmatic areas.

Both Bonneville's cyber and physical security programs are subject to regular audits by the DOE Inspector General to evaluate compliance with DOE and federal standards.

Renewable Generation Development and Integration into the Federal Transmission System

In the past few decades, Bonneville has integrated a significant number of generation projects into its balancing authority area in the Region, and is responsible for transmitting electric power into or through the Region. Integrating new resources has required and may continue to require transmission facility investments, such as new transmission lines and substations or improvements to existing facilities, in order to transmit the additional electric power. Much of the power generation development in the Region has been from wind projects. Bonneville estimates that 5,794 megawatts of wind generation facilities are now interconnected to the Federal Transmission System and approximately 2,827 megawatts are currently in Bonneville's balancing authority area. By the end of Fiscal Year 2026, Bonneville expects that it will integrate into the Federal Transmission System an additional 1,055 megawatts of wind generation facilities (bringing the total wind integrated into the Federal Transmission System to 6,849 megawatts).

From a power marketing perspective, the development of large amounts of wind generation in the Pacific Northwest has also affected power market prices and the revenue Bonneville obtains for its surplus power sales, in particular the sale of seasonal surplus energy. It has also resulted in Power Services providing significant generation capacity and energy needed to provide ancillary services needed for wind energy integration, namely generation imbalance services. Wind energy is intermittent and variable, and does not always generate energy as expected. To ensure the expected energy is available, other generating resources must stand ready to increase and decrease generation in short order to ensure expected energy amounts are delivered to load.

Integrating renewable resources, particularly wind resources, can pose other operational challenges for the Federal System. For instance, in spring and summer months, high river flows can lead to situations in which turbines at certain Federal System dams must generate electric power to protect fish populations from the harmful effects of excessive gas levels in the river. Running water though the dams' turbines rather than over the dams' spillways reduces gas formation but it unavoidably generates electric power that must be used (taken to load). This can create an oversupply of generation, which, if uncorrected would lead to power system instability. Oversupply can be resolved operationally by the substitution ("displacement") of non-federal generation (including wind generation) with Federal System hydropower.

A central feature of Bonneville's management of oversupply to protect fish is to displace wind generation at times when (i) aggregate electric generation exceeds electric system demand, (ii) increased hydroelectric generation is necessary to keep dissolved gas concentrations within acceptable limits, and (iii) displacement of non-federal generation with low-cost or free Federal System hydroelectric power is inadequate to mitigate excess gas levels. Bonneville has also established special tariff provisions, which have been approved by FERC, to compensate non-federal generators (primarily wind generators) for being displaced in oversupply events when free or low-cost Federal power displacement is inadequate to induce sufficient displacement. Bonneville recovers the costs of oversupply compensation in its rates in accordance with transmission rate provisions that have also been approved by FERC.

Almost all of the new renewable generation in the Region in the last ten years has been in the form of wind generation; however, Bonneville has seen an increase in solar power development. As with wind generation, solar power is highly variable and presents transmission system integration challenges. Solar output is easier to predict over the course of a day and is less challenging to integrate than wind generation; however, the second-to-second variability due to clouds crossing the solar site requires that Bonneville keep more spinning reserves online. Bonneville estimates that 526 megawatts of utility scale solar generation facilities are now interconnected to the Federal Transmission System and approximately 146 megawatts are currently in Bonneville's balancing authority area. By the end of Fiscal Year 2026, Bonneville expects that it will integrate into the Federal Transmission System an additional 849 megawatts of solar resources (bringing the total solar integrated into the Federal Transmission System to 1,375 megawatts).

Regional Market Initiatives

Day Ahead Markets in the West

Since 2018 through its grid modernization initiative, Bonneville has invested in modernizing its systems and processes to enhance transmission and generation operations. Such investments enabled Bonneville to make its first step into organized markets in Fiscal Year 2022 when it joined the Western Energy Imbalance Market and positions Bonneville to be prepared for other potential market development options.

Bonneville has been exploring the potential for organized energy market options to enhance the efficient delivery of reliable, affordable, and carbon-free hydropower to its customers. As part of these efforts, Bonneville is actively engaged in the development of two day-ahead energy market initiatives in the West: (i) Cal-ISO's Extended Day Ahead Market ("EDAM") and (ii) Southwest Power Pool's Markets+ ("Markets+") Day-Ahead and real-time market initiative.

Bonneville continues to evaluate the EDAM and Markets+ market development options with a focus on governance, operational and commercial impacts, and other factors before deciding whether to participate in either market. While both initiatives are still in early stages of development, Bonneville recognizes that independent governance is an essential aspect of any potential future market to ensure neutrality in market development, implementation and operation.

In February 2023, Bonneville announced a commitment of resources to support and evaluate Phase 1 development of Markets+. Bonneville's share of the total Phase 1 costs to date are approximately $1.5 million. Phase 1 funded activities through filing of the Markets+ tariff, which is nearing completion. Once the Markets+ tariff is filed, Bonneville's continued costs are expected to be approximately $75,000 per month through late 2024. The next step would be for Bonneville to make Phase 2 commitments in late 2024 or early 2025. If Bonneville continues to participate in Phase 2, Bonneville's share of Phase 2 costs are estimated to be approximately $20 million to $23 million.

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead energy market. On April 4, 2024, Bonneville published a staff recommendation to share staff's preliminary analysis, acknowledge regional input received, and clarify the next steps in its process. The staff's recommendation is for Bonneville to pursue participation in a day-ahead market and they have identified Markets+ as the preferable option of the two based on its current design and governance features. Staff analyzed the governance structure and design features of both markets through the evaluation principles established at the start of Bonneville's decision process. Bonneville plans to conduct additional analysis and public discussions prior to releasing a draft policy for public comment. Bonneville anticipates it will make a final decision regarding market participation in late 2024. If Bonneville determines that it should participate in a day-ahead energy market, its decision would be dependent on implementation in rate and tariff proceedings.

Western Resource Adequacy Program

On December 16, 2022, following the completion of a public process, Bonneville made a decision to join the binding Phase 3B of the Western Power Pool's Western Resource Adequacy Program ("WRAP"). Phase 3B is the final stage of this regional effort and follows Bonneville's participation in the WRAP's Phase 3A non-binding informational resource adequacy program. Bonneville's Phase 3B decision was contingent on certain key requirements being fulfilled, including FERC's approval of the WRAP Tariff on terms acceptable to Bonneville and FERC's acceptance of a participation agreement with unique provisions to ensure Bonneville's WRAP participation is consistent with its statutory authorities and other legal obligations.

Beginning in 2019, entities in the West have come together through an initiative facilitated by the Western Power Pool ("WPP") to scope and develop a resource adequacy program. The WRAP is the product of a proactive effort by the region to address resource adequacy concerns driven by changing factors in the energy industry due to decarbonization in multiple sectors (e.g., energy, housing and transportation) and climate change. Traditional carbon-intensive resources are being replaced with cleaner renewable resources that have different generation attributes, profiles and impacts on the interconnected energy grid than their predecessors. The WRAP uses common planning metrics to increase transparency into resources and transmission needed to reliably supply power to meet existing and future load demands in the WRAP's footprint. As more intermittent renewables are integrated into the grid and more extreme weather events occur, resource adequacy will be crucial for maintaining grid reliability in the West. The WRAP provides another tool to help ensure there is enough capacity to meet the area's power needs through coordination, established metrics and transparency among participants. In addition to increased grid reliability, the WRAP enables planning across a larger footprint using a diverse array of resources that could enable greater efficiencies and potentially reduce costs for the region's utilities and ratepayers.

Participants in the development of the WRAP initiative initially participated in a non-binding phase, which was administered by WPP for informational purposes with the goal of ultimately moving to a fully binding program. Phase 3B became effective on January 1, 2023. It includes a transition period to phase in compliance obligations and charges to support participants' transition into the binding program. Bonneville has elected winter 2027-2028 as its first binding season, when it will be required to meet all operational and compliance obligations of the program. During the non-binding transition period, Bonneville will engage in the program governance and various aspects of program implementation, including the development of the business practices and submission of data.

Several business practices have been approved by subcommittees and the independent WPP Board of Directors. Many more are in the review process and will be considered by the WPP Board of Directors as the program structure continues to solidify. Bonneville and other participants are submitting data for the non-binding forward showing evaluations and curing any deficiencies identified by WPP in preparation for the binding phase of the program.

Bonneville will continue to assess matters it identified in its Phase 3B decision letter as it gains experience with the program during the non-binding transition period. Bonneville has committed to continued engagement with its customers and other interested parties during the transition period. Bonneville will identify and report relevant program impacts to customers as part of its ongoing public engagement. Based on Bonneville's experience with the program during the transition period, Bonneville may reevaluate its winter 2027-2028 decision and has the ability to move its binding season to an earlier season on two years' notice.

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

Prior to 1974, Congress annually appropriated funds for the payment of Bonneville's obligations, including working capital expenditures. Under the Transmission System Act, Congress created the Bonneville Fund, a continuing appropriation available to meet all of Bonneville's cash obligations.

All receipts, collections, and recoveries of Bonneville in cash from all sources are now deposited in the Bonneville Fund. These include revenues from the sale of power and other services, trust funds, proceeds from the sale of bonds by Bonneville to the United States Treasury, any appropriations by Congress for the Bonneville Fund, and any other Bonneville cash receipts.

Bonneville is authorized to make expenditures from the Bonneville Fund without further appropriation and without fiscal year limitation if such expenditures have been included in Bonneville's annual budget to Congress. However, Bonneville's expenditures from the Bonneville Fund are subject to such directives or limitations as may be included in an appropriations act. Bonneville's annual budgets are reviewed by the DOE and subsequently by the United States Office of Management and Budget. The Office of Management and Budget includes Bonneville's budget in the President's budget submitted to Congress.

The existence of the Bonneville Fund also enables Bonneville to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount of cash in the Bonneville Fund and available borrowing authority. Pursuant to the Project Act and other law, Bonneville has broad authority to enter into contracts and make expenditures to accomplish its objectives.

No prior budget submittal, appropriation, or any prior Congressional action is required to create such obligations except in certain specified instances. These include construction of transmission facilities outside the Region, construction of major transmission facilities within the Region, construction of certain fish and wildlife facilities, condemnation of operating transmission facilities, and acquisition of certain major generating or conservation resources.

The Federal System Investment

The total cost of the multipurpose Federal System Hydroelectric Projects that are part of the Federal System is allocated among the purposes served by the projects, which may include flood control, navigation, irrigation, municipal and industrial water supply, recreation, the protection, mitigation, and enhancement of fish and wildlife, and the generation of power. The costs allocated to power generation from the Corps and Reclamation projects as well as the cost of the transmission system prior to 1974 have been funded through appropriations. The capital costs of the transmission system since 1974 and certain capital conservation and fish and wildlife costs since 1980 have been funded in great part through the use of Bonneville's borrowing authority with the United States Treasury or through Bonneville's Non-Federal Debt Programs.

Bonneville is required by statute to establish rates that are sufficient to repay its Federal Appropriations Repayment Obligations within a reasonable period of years. The statutes, however, are not specific with regard to directives for the repayment of the Federal System investment, including what constitutes a reasonable period of years. Consequently, the details of the repayment policy have been established through administrative interpretation of the basic statutory requirements. The current administrative interpretation is embodied in the United States Secretary of Energy's directive RA 6120.2. The directive provides that Bonneville must establish rates that are sufficient to repay the federal investments within the average expected service life of the facility or 50 years, whichever is less. Bonneville develops a repayment schedule both to comply with investment due dates and to minimize costs over the repayment period. Costs are minimized, in accordance with the United States Secretary of Energy's directive RA 6120.2, by repaying the highest interest bearing investments first, to the extent possible. This method of determining the repayment schedule would result in some investments being repaid before their due dates, while assuring that all investments will be repaid by their due dates. As of September 30, 2023, Bonneville had repaid $18.4 billion of principal of the Federal System investment and had approximately $1.6 billion principal amount outstanding with regard to such appropriated investments and $5.8 billion principal amount outstanding in bonds issued by Bonneville to the United States Treasury. Congress has continued to, and is expected to continue to, appropriate amounts for certain fish and wildlife investments in the Federal System. See the discussion of the Columbia River Fish Mitigation in "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Bonneville's repayment obligations include the payment of "irrigation assistance," which relates to appropriations provided to Reclamation to construct irrigation facilities associated with its Federal System projects. Bonneville's irrigation assistance obligation is limited to an amount of appropriations that is deemed under Reclamation policy to be beyond the ability of irrigators to pay. Examples of appropriated irrigation investments include water pumps, reservoir facilities and canals within the authorizations for the Federal System Hydroelectric Projects owned by Reclamation. These repayment obligations do not incur interest. In keeping with the principle (as embodied in DOE Order RA 6120.2) of scheduling repayments on the basis of highest interest repayment obligations first, payments for irrigation assistance are typically scheduled for recovery in Bonneville power rates in the year in which the expected life of the related facility (as determined near the time of construction) is reached. Bonneville expects that these payments will range between $2 million and $21 million per year over the next ten years.

Internal Guidance Affecting Bonneville Financial Operations

In August 2023, Bonneville published the 2024-2028 Strategic Plan that identified the prioritized set of actions Bonneville expects to take to improve Bonneville's commercial performance and position it to adapt to a rapidly transforming energy industry. The 2024-2028 Strategic Plan sets forth the following five strategic goals: (i) strengthen financial health; (ii) modernize assets and system operations; (iii) provide competitive power products and services; (iv) meet transmission customer needs efficiently and responsively; and (v) value people and deliver results. The supporting Financial Plan, initially published in February 2018, outlined three financial health objectives that guide Bonneville's focus on financial health: (i) cost management discipline, (ii) financial resiliency, and (iii) independent financial health assessment. These objectives are designed to support Bonneville's ability to deliver on its mission and meet its multiple statutory obligations under various conditions. On September 30, 2022, Bonneville published its 2022 Financial Plan. Bonneville continues to focus on its financial health objectives and has set a specific long-term debt-to-asset ratio target.

Bonneville previously employed a Leverage Policy that guided Bonneville's debt management practices. The Leverage Policy required that each business line maintain or decrease its debt-to-asset ratio over time and set a target debt-to-asset ratio of 75-85 percent by Fiscal Year 2028 and a long-term target debt-to-asset ratio of 60-70 percent beyond Fiscal Year 2028. As part of its efforts to publish the 2022 Financial Plan, Bonneville adopted a Sustainable Capital Financing Policy that establishes guidelines around how Bonneville will obtain funds for its capital investment program and also provides an updated debt-to-asset ratio target. The Sustainable Capital Financing Policy supersedes the Leverage Policy and provides a long-term target debt-to-asset ratio of 60 percent by Fiscal Year 2040. At a minimum, each business line will fund ten percent of its capital program with revenue financing. The remainder is to be funded with bonds issued to the United States Treasury or by other means. When establishing rate case assumptions for development of rates for each rate period, if a business line is not on a path to achieve a 60 percent debt-to-asset ratio by 2040, it will incrementally increase the amount of revenue financing to fund 20 percent of its capital program; however, the amount of revenue financing is capped to ensure that the total amount of revenue financing for a business line will not result in more than a one percent rate increase.

Since release of the plans, Bonneville has made progress towards each of its financial objectives. At the end of Fiscal Year 2023, Bonneville's Days Cash on Hand was 193 days, significantly exceeding the minimum threshold outlined in the Financial Plan. At the end of the Fiscal Year 2023, the agency debt-to-asset ratio was 81 percent. In the Final 2024-2025 Rates, both power and transmission rates include a planned amount of revenue financing in each of the two fiscal years of the rate period (which averaged $34 million per year for power and averaged $55 million per year for transmission), which is contributing to improvement of the overall debt-to-asset ratio. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments."

Bonneville's Treasury Borrowing Authority

Bonneville is currently authorized to issue and sell to the United States Treasury, and to have outstanding at any one time, up to $13.7 billion aggregate principal amount of bonds. Beginning in Fiscal Year 2028, an additional $4 billion will become available as provided for in the Infrastructure Investment and Jobs Act legislation that authorized the $10 billion increase. Of the $13.7 billion in borrowing authority that Bonneville has with the United States Treasury, bonds in the principal amount of $5.8 billion were outstanding as of the end of Fiscal Year 2023. To reduce overall interest expense, Bonneville may delay borrowing from the United States Treasury until necessary from a cash flow perspective which increases the Deferred Borrowing (as hereinafter defined) balance. For more details related to Deferred Borrowing, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." If the full amount of Deferred Borrowing reported as part of Bonneville's Total Financial Reserves had been borrowed at the end of Fiscal Year 2023, the total amount of bonds outstanding as of the end of Fiscal Year 2023 would have been $5.8 billion. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 annual average megawatts. Of the currently available $13.7 billion in United States Treasury borrowing authority, $1.3 billion is available for electric power conservation and renewable resources, including capital investment at the Federal System hydroelectric facilities owned by the Corps and Reclamation, and $12.5 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. As of the end of Fiscal Year 2023, the interest rates on the outstanding bonds ranged from 0.4 percent to 5.9 percent with a weighted average interest rate of approximately 3.4 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2023, Bonneville's outstanding bonds issued to the United States Treasury included $495 million in variable rate bonds at an average interest rate of 5.48 percent at such time. The term of the bonds is limited by the average expected service life or the maximum repayment period, whichever is shorter, of the associated investment: 35 years for transmission facilities, 50 years for Corps and Reclamation capital investments, up to 20 years for conservation investments, and 15 years for fish and wildlife projects. Bonds are issued with call options.

Banking Relationship between the United States Treasury and Bonneville

Effective April 30, 2008, Bonneville entered into an Obligation Purchase Memorandum of Understanding ("Obligation Purchase MOU") governing the terms by which Bonneville borrows from the United States Treasury. The banking arrangement enables Bonneville to borrow for long- and short-term capital needs and for short-term operating expenses. Under the short-term operating expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating expense advances can be made available on as short as one day's notice and have a maximum repayment period of one year, although Bonneville may extend the maturities an additional year by exercising certain rights that would re-establish applicable interest rates. Nothing in the banking arrangement increases the statutory limit on the aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time. In recent years, Bonneville has made draws on the short-term operating expense note but has repaid such draws prior to the end of the fiscal year in which the draws were made.

Coincident with the entry into the Obligation Purchase MOU, Bonneville and the United States Treasury entered into an Investment Memorandum of Understanding ("Investment MOU") that governs investments in the Bonneville Fund. Under the Investment MOU, Bonneville invests the applicable cash reserves in the Bonneville Fund in certain interest bearing securities ("market-based special securities") issued by the United States Treasury. In general, the market-based special securities bear interest by reference to the published yield curve for United States Treasury debt at the time of the investment.

The United States Treasury's ability to meet requests by Bonneville may be affected by a failure to raise the United States Treasury debt borrowing ceiling. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Federal Debt Ceiling."

Bonneville's Non-Federal Debt

To meet its capital program, Bonneville has relied on the Congressionally-enacted authority to borrow from the United States Treasury; however, Bonneville has also entered into various arrangements to meet its capital program which involve debt issued by third parties, the repayment of which is secured by Bonneville financial commitments. Bonneville has also employed electric power prepayments as a funding source. Bonneville refers to these commitments as "Non-Federal Debt." As of September 30, 2023, aggregate Non-Federal Debt outstanding was approximately $7.4 billion. By way of comparison, as of September 30, 2023, the principal amount of unrepaid appropriations for Federal System investments was approximately $1.6 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was $5.8 billion. Described below are the currently outstanding forms of Non-Federal Debt and a description of possible Non-Federal Debt transactions in the near future.

Bonds for Energy Northwest's Net Billed Projects

Bonds and other debt instruments issued by Energy Northwest and secured by Net Billing Agreements referred to herein as "Net Billed Bonds" represent the largest single component of Non-Federal Debt: $5.2 billion out of a total of $7.4 billion aggregate Non-Federal Debt, as of September 30, 2023. Bonneville works with Energy Northwest on debt management actions relating to Net Billed Bonds.

As described in this section, under certain Net Billing Agreements, Bonneville has acquired indirectly from Energy Northwest the electric power capability of three large nuclear generating projects ("Energy Northwest Net Billed Projects"). Two of the projects ("Project 1" and "Project 3") were partially constructed before being terminated in the 1990s. The third project, the Columbia Generating Station, was completed and is operating. In May 2012, the Nuclear Regulatory Commission granted an operating license extension for Columbia Generating Station through calendar year 2043.

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (as amended, the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its ownership share of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (as amended, the "Project 3 Net Billing Agreements," which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Under the Net Billing Agreements, each Participant assigned its share of the capability of the related Net Billed Project to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project.

Under the Net Billing Agreements, in payment for the share of the capability of each Energy Northwest Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Energy Northwest Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's billing statement. Bonneville is obligated to pay this amount to such Participant by providing net billing credits against the amounts such Participant owes Bonneville under the Participant's power sales and other contracts with Bonneville and by making the cash payments described below. Each Participant is obligated to pay Energy Northwest an amount equal to the amount of such credits and cash payments as payment on account of its obligations to pay for its share of the Net Billed Project capability.

The Net Billing Agreements provide for cash payments and the provision of credits by Bonneville and payments by Participants whether or not the related Energy Northwest Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Energy Northwest Net Billed Project output or termination of the related Energy Northwest Net Billed Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

The Net Billing Agreements require each Participant to pay Energy Northwest the amount set forth in its billing statement. Each Participant is required to make payments to Energy Northwest only from revenues derived by the Participant from the ownership and operation of its electric utility properties and from payments made by Bonneville under the Net Billing Agreements. Each Participant has covenanted that it will establish, maintain and collect rates or charges for power and energy and other services furnished through its electric utility properties which shall be adequate to provide revenues sufficient to make required payments to Energy Northwest under the Net Billing Agreements and to pay all other charges and obligations payable from or constituting a charge and lien upon such revenues.

The amounts potentially subject to net billing are substantial. The debt service on the Net Billed Bonds in Fiscal Year 2023 was $198 million. In addition, the operations and maintenance expense for the Columbia Generating Station in Fiscal Year 2023 was $316 million.

Since 2001, Energy Northwest, a joint operating agency of the State of Washington, and Bonneville have worked together to refinance certain maturities of outstanding Net Billed Bonds so that the weighted average maturities more closely match the originally expected useful lives of the related Net Billed Project facilities. The most recent efforts are known as "Regional Cooperation Debt."

Bonneville manages its overall debt portfolio, which includes Non-Federal Debt and Bonneville's repayment obligations to the United States Treasury, to meet the objectives of: (i) minimizing the cost to Bonneville's ratepayers, (ii) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs, and (iii) maintaining sufficient financial flexibility to meet Bonneville's financial requirements.

Bonneville's Strategic and Financial Plans, initially published in 2018, identified continued access to low-cost capital and preservation of Bonneville's United States Treasury borrowing authority capacity (including the goal of retaining a minimum of $1.5 billion of United States Treasury Borrowing Authority) as key to Bonneville's long-term financial health. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program—Bonneville's Capital Financing Strategy" and "—Internal Guidance Affecting Bonneville Financial Operations." To address this need, Energy Northwest and Bonneville worked together to restructure Regional Cooperation Debt beyond the initial phase in a way that provides flexibility to shape and stabilize capital related costs over time. In September 2018, the Energy Northwest Board adopted a motion supporting the extension of the Regional Cooperation Debt initiative through Fiscal Year 2030; the issuance of additional Net Billed Bonds will require approval of the Energy Northwest Board.

The current phase of Regional Cooperation Debt refinancings has and will have the effect of freeing up amounts in the Bonneville Fund which otherwise would have been used to fund the repayment of the principal of the refunded Net Billed Bonds. In addition, this phase of Regional Cooperation Debt also includes the issuance of Net Billed Bonds to fund a portion of the interest coupon payments allocable to unamortized bond premiums related to certain outstanding Net Billed Bonds. The freed up funds resulting from the refinancings or issuance of Net Billed Bonds for interest coupon payments would enable Bonneville (i) to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury to help restore or preserve Bonneville's available capacity of its United States Treasury borrowing authority or (ii) to directly fund Bonneville capital investments.

Bonneville expects that Energy Northwest will continue to issue Net Billed Bonds to fund new capital investments for the Columbia Generating Station which are expected to be made in the amount of approximately $2.8 billion from July 2023 through June 2034. Additional Net Billed Bonds for additional capital investments for Columbia Generating Station may be issued thereafter. In addition, Bonneville expects to continue to work with Energy Northwest to issue up to an additional $2.6 billion of Net Billed Bonds through 2030 to: (i) refinance certain Net Billed Bond debt to extend the average maturity of the outstanding principal balance of such debt to match more closely the originally expected economic useful lives of the facilities financed thereby, or (ii) fund a portion of the interest coupon payments related to certain outstanding Net Billed Bonds. In Fiscal Year 2023, Energy Northwest issued approximately $340 million of Net Billed Bonds under the Regional Cooperation Debt approach which enabled Bonneville to prepay approximately $401 million of outstanding Federal Debt over the amounts that Bonneville was scheduled to repay in Fiscal Year 2023.

Bonneville's Transmission Facility Lease-Purchase Program

One type of Non-Federal Debt involves the entry by Bonneville into lease-purchase agreements to acquire the use of transmission assets owned by a third party. Bonneville's lease-purchase payments are pledged by the related project owner to the payment of certain short-term bank loans that the owner incurs or long-term bonds that the owner issues to the public. The proceeds of the bank loans or bonds are used to fund the acquisition of and or construction, installation, and equipping of, the related facilities. Under these transactions, the related bonds and bank loans are secured solely by Bonneville's payments under the related lease-purchase agreement; furthermore, Bonneville's related lease rental payments are not conditioned on the completion, suspension, or termination of the related facilities.

Bonneville currently has one outstanding short-term lease-purchase arrangement and two long-term lease-purchase arrangements with the Idaho Energy Resources Authority ("IERA"), one long-term lease-purchase arrangement with Northwest Infrastructure Financing Corporation, and seven long-term lease-purchase arrangements with the Issuer. The Series 2024 Bonds when issued will be included in Non-Federal Debt under the Lease-Purchase Program.

The aggregate principal amount of an outstanding bank loan and publicly-issued bonds associated with Bonneville's lease-purchase agreements was $2.0 billion as of September 30, 2023. Of the foregoing amount, approximately $81 million of the aggregate outstanding principal amount is related to a bank loan associated with a short-term lease-purchase agreement that terminates in Fiscal Year 2025, which Bonneville expects to fund from the Series 2024 Bonds.

As described in the Official Statement, the Issuer will use the proceeds from the sale of the Series 2024 Bonds to acquire the Project from IERA that were initially financed with the bank loan associated with the IERA short-term lease-purchase arrangement mentioned above. See the Official Statement under "INTRODUCTORY STATEMENT" and "PURPOSE OF ISSUANCE AND USE OF PROCEEDS." The Series 2024 Bonds will be secured solely by the Issuer's pledge of Bonneville's rental payments under the Lease-Purchase Agreement.

Electric Power Prepayments

In Fiscal Year 2013, Bonneville and four Preference Customers agreed to separate electricity prepayment arrangements in which the Preference Customers provided lump-sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028, the termination date of the Long-Term Preference Contracts. The participating customers are entitled to future deliveries of a portion of the electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments is and will be reflected as fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville received $340 million in aggregate of prepayments from the participating customers, all of which has been expended on Federal System hydroelectric facility investments. The offsetting prepayment credits are set at $2.55 million per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028.

As of September 30, 2023, outstanding Non-Federal Debt associated with electric power prepayments was $139 million.

While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use electric power prepayments to meet some of its future capital funding needs.

Resource Acquisitions

Under this form of Non-Federal Debt, Bonneville enters into resource acquisition agreements in which a third party issues bonds, the proceeds of which are used to construct or acquire generating facilities or to fund energy conservation measures, the project capability or conservation savings of which are provided to Bonneville. As of September 30, 2023, outstanding Non-Federal Debt for generating resource acquisitions was $56 million. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies—Electric Power Conservation." While Bonneville has no current plans to do so, it may seek to use this form of Non-Federal Debt to acquire electric power generating and conservation resources to meet some of its future capital funding needs.

Total Non-Federal and Federal Debt

The following table depicts the types and amounts of Non-Federal and Federal Debt outstanding as of the end of each of Fiscal Years 2021 through 2023. Any discrepancies in totals for figures portrayed in this table are due to rounding.

Non-Federal and Federal Debt, Fiscal Years 2021-2023
(Dollars in millions)

Non-Federal and Federal Debt Outstanding

Projects Financed with Non-Federal Debt	**2023**	**2022**	**2021**
Non-Federal Generation			
Columbia Generating Station	$3,382	$3,296	$3,247
Cowlitz Falls Project	52	56	61
Terminated Generation			
Nuclear Project No. 1	837	824	809
Nuclear Project No. 3	971	950	930
Northern Wasco Hydro Project	4	5	7
Lease-Purchase Program	1,886	1,957	2,029
Finance Lease/Other Financial Liability	120	118	114
Customer prepaid power purchases	139	163	186
Total Non-Federal Debt	$7,391	$7,369	$7,383
Federal Debt			
Borrowings from U.S. Treasury	5,784	5,679	5,629
Federal appropriations	1,124	1,243	1,233
Federal appropriations (not yet scheduled for repayment)	474	398	370
Total Federal Debt	$7,382	$7,320	$7,232
Total Debt	**$14,773**	**$14,689**	**$14,615**

To the extent that Bonneville has entered into (or will enter into) arrangements involving Non-Federal Debt secured by cash payments by Bonneville, such as transmission facility lease-purchase arrangements and electric power conservation or generating resource acquisitions, the related debt service costs are and will be payable on the same parity as the lease rental payments for the Project under the Lease-Purchase Agreement in the order in which Bonneville's costs are met. See "—Order in Which Bonneville's Costs Are Met." To the extent that Bonneville uses Non-Federal Debt that involves the provision by Bonneville of financial credits or offsets (including net billing credits with respect to the Net Billed Projects), such obligations may reduce the amount of cash otherwise available in the Bonneville Fund to meet Bonneville's cash payment obligations, including lease rental payments for the Project under the Lease-Purchase Agreement.

Bonneville's Capital Program

Bonneville operates in a capital intensive industry and expenditure levels for its capital program have been substantial. As with all capital investments, there is potential that certain investments may not be constructed to completion, provide the results expected, or achieve functionality for their full expected useful lives. The following table depicts Bonneville's capital investment levels by asset category for Fiscal Years 2019-2023. The following table excludes appropriated capital funding received by the Corps and Reclamation and capital investments associated with the Columbia Generating Station.

Historical Capital Spending by Program by Fiscal Year[1]
(Dollars in millions)

	2019	2020	2021	2022	2023	Total
Transmission[2]	$432	$371	$413	$497	$650	**$2,363**
Federal System Hydro	200	178	203	192	208	**981**
Fish and Wildlife	22	40	41	16	15	**134**
Facilities, Information Technology, Security[2]	10	20	23	16	13	**82**
Total	**$664**	**$609**	**$680**	**$721**	**$886**	**$3,560**

(1) Amounts include an Allowance for Funds Used during Construction ("AFUDC"), as applied in accordance with Bonneville's accounting policy as described in Appendix B-1 to the Official Statement (Note 1 to Financial Statements). AFUDC is a measure of interest on funds borrowed to construct electric utility plant to completion and operation.

(2) Certain amounts for Facilities, Information Technology, and Security related to Transmission Services are reported under Transmission.

To date Bonneville has met its capital program needs through various sources that include borrowing from the United States Treasury, and transactions involving Non-Federal Debt, as described above. Bonneville also uses funds from reserves and funds from customers in connection with "Projects Funded in Advance." Projects Funded in Advance are specific transmission capital investments that are made by Bonneville in the Federal Transmission System at the request of a customer or to meet a customer's transmission needs. The customer provides funds to Bonneville to construct all or a portion of the related facilities and in some circumstances certain customers may receive offsetting payment credits in future transmission bills from Bonneville. Bonneville owns the facilities in its own name. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System." The following table presents Bonneville's capital funding sources for Fiscal Year 2019 through Fiscal Year 2023. It excludes capital investments for the Columbia Generating Station and for the Columbia River Fish Mitigation as appropriated by Congress to the Corps.

Historical Capital Funding by Source and Fiscal Year[1]
(Dollars in millions)

	2019	2020	2021	2022	2023	Total
Borrowing from United States Treasury	$425	$520	$617	$606	$822	**$2,990**
Lease-Purchases[2]	37	38	22	-	-	**97**
Projects Funded in Advance	106	25	15	35	24	**205**
Revenue Funding	15	26	26	80	40	**187**
Electric Power Prepayments[3]	81	-	-	-	-	**81**
Total	**$664**	**$609**	**$680**	**$721**	**$886**	**$3,560**

(1) Reflects actual capital expenditures funded by the related source, not the amount of the debt (or related liability) by source.

(2) See "—Bonneville's Non-Federal Debt—Bonneville's Transmission Facility Lease-Purchase Program."

(3) See "—Bonneville's Non-Federal Debt—Electric Power Prepayments."

Bonneville's Capital Investment Expectations and Capital Process

To meet a variety of needs, Bonneville is forecasting aggregate planned capital expenditures comparable to or larger than levels in the recent past. Bonneville expects to fund substantial investment: (i) in the Federal Transmission System to assure reliable and secure operation of existing facilities and to address new demands (such as integrating wind generation), (ii) in the hydroelectric dams of the Federal System to maintain and improve reliability and performance, and to protect fish and wildlife, and (iii) to meet fish and wildlife capital commitments under the Columbia Basin Fish Accords, the applicable Columbia River System biological opinions, and the 2008 Willamette BiOp. Bonneville's capital expenditures also include information technology, cyber and physical security, certain heavy equipment and certain costs related to financing.

In 2016, Bonneville introduced its Asset Management Key Strategic Initiative ("KSI") designed to bring a focus to asset management. Central to the focus is the effort to more closely align Bonneville's asset management program with ISO 55000 Asset Management as outlined in the Institute of Asset Management principles and practices. The key components of that alignment are strategic asset management plans ("SAMPs") and asset plans ("Asset Plans"), first developed by Bonneville in 2018. The SAMPs are a strategic document produced bi-annually in support of Bonneville's rate setting process. Asset Plans are produced annually and describe implementation of the SAMPs for a particular fiscal year.

The SAMPs provide a strategic approach that aligns with the goals in the 2024-2028 Strategic Plan. See "—Bonneville's Capital Financing Strategy." The more detailed and near-term Asset Plans are generally developed from the SAMPs. Each plan is created by using methodologies, dependent upon their asset management maturity, which calculates the investment needs. This process seeks to balance the often competing goals of keeping Bonneville's power and transmission rates as low as possible consistent with sound business principles, making timely and needed investments in the Federal System, and assuring sustainable long-term financial health. Planned investments at the Columbia Generating Station and certain other investments that Bonneville believes are not within its direct control to determine are considered in long-term rate analysis but are not part of the asset management processes, such as the SAMPs and Asset Plans, nor subject to these capital investment strategies.

Most of Bonneville's capital investments involve renewals, upgrades and replacement of existing facilities and are incremental in character.

In connection with developing the Final 2024-2025 Rates, Bonneville has assumed the capital spending levels shown in the table that follows, with the exception of Fiscal Year 2024 details that are sourced from Bonneville's Fiscal Year 2024 year-end forecast as of December 31, 2023. These spending levels reflect the preliminary outcome of Bonneville's capital prioritization process and do not include the effort referred to as the Evolving Grid Projects which could include an additional $2 billion of transmission projects through Fiscal Year 2032. For more details regarding the Evolving Grid Projects, See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

Forecast Capital Spending by Program and Fiscal Year
(Dollars in millions)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Transmission	$590	$528	$538	$545	$550	$542	$547	$531	$532	$534	**$5,437**
Fed System Hydro	214	276	282	288	295	302	309	316	324	331	**2,937**
Fish and Wildlife	42	41	29	16	15	15	15	15	15	15	**218**
Facilities, Information Technology, Security	105	131	96	69	75	73	72	74	74	77	**846**
AFUDC(1)	40	27	28	28	28	28	28	28	28	28	**291**
Total	**$991**	**$1,003**	**$973**	**$946**	**$963**	**$960**	**$971**	**$964**	**$973**	**$985**	**$9,729**

(1) AFUDC is based on forecasts of spend rates, completion dates and interest rates. AFUDC will be applied to specific program projects as construction begins and will accumulate during the construction period in accordance with Bonneville's accounting policy as described in Appendix B-1 to the Official Statement (Note 1 to Financial Statements).

The Forecast Capital Spending table above does not include investments projected by Energy Northwest for the Columbia Generating Station. Energy Northwest has developed a long-term capital investment strategy for the Columbia Generating Station in view of a 20-year operating license extension, evolving and expected guidance from the Nuclear Regulatory Commission, and other factors. The strategy identified $2.8 billion in additional capital requirements from July 2024 through June 2034. Bonneville expects that new capital needs for the project will be funded with Net Billed Bonds issued by Energy Northwest, the debt service of which will be covered by Bonneville under Net Billing Agreements. See "—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects." The Forecast Capital Spending table above also does not include investments related to the Columbia River Fish Mitigation program as appropriated by Congress to the Corps. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife."

There is substantial uncertainty in forecasting capital program needs. Actual capital spending can differ substantially from forecasts due to various factors including, among other things, changing needs, customer demands and input, expected rate impacts, and changes in expected costs, regulatory requirements, technology, asset prioritization, and the availability of non-capital investment alternatives.

Bonneville's Capital Financing Strategy

Given the large amount of potential Federal System investment described above, and based on current and forecast capital spending levels, and the amount of available United States Treasury borrowing authority, Bonneville has worked and continues to work with its customers to develop a strategic approach to assure that current capital investment sources described in the table above, including Non-Federal Debt (see "—Bonneville's Non-Federal Debt—Net Billed Bonds"), and borrowing from the United States Treasury, and other means, are sufficient to meet Bonneville's capital program and liquidity needs. Bonneville believes that Non-Federal debt actions, combined with Bonneville's recently increased United States Treasury borrowing authority capacity and other actions under its Financial Plan (see "—Internal Guidance Affecting Bonneville Financial Operations") will enable Bonneville to meet its capital and financial liquidity needs beyond Fiscal Year 2044.

Direct Pay Agreements

In Fiscal Year 2006, Bonneville and Energy Northwest entered into certain Direct Pay Agreements. Under these agreements, Bonneville has agreed by contract to pay directly to Energy Northwest the costs of Columbia Generating Station, Project 1, and Project 3 as billed to Bonneville by Energy Northwest. Under these agreements, Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both federal and non-federal.

In reliance on Bonneville's Direct Pay Agreement obligations, the billing statements that Energy Northwest is required to provide to Participants under the Net Billing Agreements show and will show the expected payments from Bonneville under the Direct Pay Agreements as amounts payable from sources other than the Net Billing Agreements. Thus, the amounts to be paid by Participants to Energy Northwest in a Net Billing Agreement Contract Year are and will in the future be reduced to zero, thereby reducing Bonneville's obligation to provide net billing credits to zero as well. In this manner, Bonneville meets and will meet the costs of the Net Billed Projects on a current basis entirely by means of cash payments from the Bonneville Fund.

The Direct Pay Agreements did not and do not result in the amendment or termination of the Net Billing Agreements or any other agreements of Bonneville with respect to the Net Billed Projects. The Direct Pay Agreements provide that, in the event that Bonneville were to fail to make required payments under the Direct Pay Agreements, Energy Northwest would re-initiate net billing as required under the Net Billing Agreements. In the event that payments under the Direct Pay Agreements were to fall short of meeting Net Billed Project costs or the Direct Pay Agreements were terminated, under the Net Billing Agreements, the Participants would resume making payments directly to Energy Northwest and Bonneville would resume crediting (net billing) amounts otherwise due to Bonneville by the Participants for power and transmission purchases from Bonneville, up to the amount of payments made by the Participants to Energy Northwest. In general, the amount of the Participants' payments subject to net billing is based on the amount of transmission and power purchased from Bonneville and the rates charged by Bonneville for such purchases.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now “direct funds” virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville’s cash payments for operations and maintenance expense to the Corps, Reclamation, and the Fish and Wildlife Service were $265 million, $160 million, and $32 million, respectively, in Fiscal Year 2023.

Bonneville believes that the direct funding approach has increased Bonneville’s influence on the Corps’ and the Department of Interior’s Federal System operations and maintenance activities, expenses, and budgets because, in general, Bonneville’s approval is necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville’s non-federal obligations, including Bonneville’s payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct funding would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct funding could be made to the exclusion of non-federal payments that would otherwise have been paid under historical practice. One result of direct funding obligations by Bonneville is that there has been and will be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville’s repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, Bonneville expects to have approximately $633 million to $883 million in scheduled payments and planned discretionary payments each year to the United States Treasury, exclusive of the Corps’ and the Department of Interior’s operations and maintenance expenses, through Fiscal Year 2028. Bonneville has renewed and extended the direct funding operations and maintenance agreement with the Corps through Fiscal Year 2033. The direct funding operations and maintenance agreement with the Department of Interior is indefinite and does not require periodic renewals.

Order in Which Bonneville’s Costs Are Met

Bonneville is required to establish rates sufficient to make, and Bonneville makes, certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at the Federal System Hydroelectric Projects, (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury, (iii) repayment of appropriated amounts to the Corps and Reclamation for costs that are allocated to power generation at the Federal System Hydroelectric Projects, and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its Fiscal Year 2023 payment responsibility to the United States Treasury in full and on time.

For various reasons, Bonneville’s revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all non-United States Treasury cash payment obligations of Bonneville, including lease rental payments for the Project under the Lease-Purchase Agreement; and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville’s General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including lease rental payments for the Project under the Lease-Purchase Agreement; and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See “—Direct Pay Agreements.”.

Bonneville's operating revenues include amounts equal to net billing credits if and as provided by Bonneville under the Net Billing Agreements, see "—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects" and "—Direct Pay Agreements" above. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Energy Northwest Net Billing Agreements for the Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. Bonneville and Energy Northwest have entered into Direct Pay Agreements under which Bonneville pays the costs of the Net Billed Projects on a current cash basis thereby reducing the use of net billing to meet the costs of the Net Billed Projects. See "—Direct Pay Agreements."

Bonneville also has obligations to reduce future amounts receivable from certain power customers that have prepaid for electric power, see "—Bonneville's Non-Federal Debt—Electric Power Prepayments," and from certain transmission customers that have provided lump sum payments to Bonneville for it to construct or install certain transmission facilities necessary to provide transmission service to the customers. The electric power prepayments involve the recognition (as credits) of the prepayments in future electric power bills by Bonneville. The credits for prepaid power will be approximately $31 million per fiscal year through Fiscal Year 2028. Transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were $20 million in Fiscal Year 2023. Bonneville estimates that transmission service credit offsets will be $20 million in Fiscal Year 2024. The foregoing credits have the effect of reducing Bonneville's future cash revenue from the participating customers, and will reduce in the future the amount of cash in the Bonneville Fund that would otherwise be available to meet Bonneville's cash payment obligations, including lease rental payments under the Lease-Purchase Agreement.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of payments to the United States Treasury in the event that net proceeds were not sufficient for Bonneville to make its annual payment in full to the United States Treasury. This could occur if Bonneville were to receive substantially less revenue or incur substantially greater costs than expected.

Under the repayment methodology as specified in the United States Secretary of Energy's directive RA 6120.2, amortization of the Federal System investment is paid after all other cash obligations have been met. If, in any year, Bonneville has insufficient cash to make a scheduled amortization payment, Bonneville must reschedule amortization payments not made in that year over the remaining repayment period. If a cash under-recovery were larger than the amount of planned amortization payments, Bonneville would first reschedule planned amortization payments payable to the U.S. Treasury and then defer current interest payments payable to the U.S. Treasury. When Bonneville defers an interest payment associated with repayment of appropriated Federal System investment in the Federal System, the deferred amount may be assigned a market interest rate determined by the Secretary of the United States Treasury and must be repaid before Bonneville may make any other repayment of principal to the United States Treasury. See the table under the heading "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments" for historical United States Treasury payments.

While all amounts in the Bonneville Fund are available to pay Bonneville's costs without regard to whether such costs are Power Services' costs or Transmission Services' costs, some reserves are derived from Power Services' rates and operations and some are derived from Transmission Services' rates and operations. (As of the end of Fiscal Year 2023, approximately $1.1 billion in Total Financial Reserves (cash, investments in United States Treasury market-based special securities and Deferred Borrowing (as defined below)) were derived from Power Services' rates and operations and $627 million in Total Financial Reserves were derived from Transmission Services' rates and operations.) "Total Financial Reserves" is an unaudited metric that is not in accordance with GAAP but which Bonneville uses to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. See "—Bonneville's Use of Non-GAAP Financial Metrics."

Because Bonneville's power rates are to be established to recover the costs of power operations and Bonneville's transmission rates are to be established to recover the cost of transmission operations, if Bonneville were to use Transmission Services-derived reserves to pay Power Services' costs, use of the Transmission Services' reserves would be treated as an obligation of Power Services, with the requirement that Power Services replenish any amounts of Transmission Services-derived reserves so used. Similarly, if Bonneville were to use Power Services-derived reserves to pay Transmission Services' costs, use of the Power Services' reserves would be treated as an obligation of Transmission Services, with the requirement that Transmission Services replenish any amounts of Power Services-derived reserves so used.

Bonneville's Use of Non-GAAP Financial Metrics

For a variety of reasons, Bonneville has developed and employs certain financial metrics that Bonneville management believes are descriptive of Bonneville's financial performance notwithstanding that such financial metrics are not consistent with GAAP and are unaudited.

Reserves Available for Risk. For ratemaking purposes, Bonneville uses a financial metric it refers to as "Reserves Available for Risk," or "RAR," as a measure of financial reserves. While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations. See "—Management's Discussion of Operating Results—Fiscal Year 2023." The RAR metric represents amounts in, or reliably available to, the Bonneville Fund which are generated through normal operations and excludes deposits from third parties, capital funds drawn in advance, borrowings for expenses and other amounts deemed by Bonneville not to be available for risk.

As of the end of Fiscal Year 2023, Bonneville had $1.3 billion in RAR and a $750 million short-term credit facility (available to meet certain expenses) with the United States Treasury (the "United States Treasury Short-Term Credit Facility"). The RAR balances and the short-term borrowing facility combine to provide a cushion of liquidity for Bonneville to meet its costs in situations where revenues and expenses deviate from rate case assumptions. Bonneville forecasts and assesses uncertainty in expenses, revenues, and cash flow through the end of the rate period. Bonneville models the effect of these uncertainties on RAR and short-term liquidity, given proposed rates. This assessment yields information about several key metrics, including TPP, which is the probability that Bonneville will be able to make all payments to the United States Treasury during the rate period. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." Depending on numerous variables, assumptions and forecasts, Bonneville may establish rates that, on average, will increase (or decrease) RAR for the relevant business line in the applicable rate period in amounts that are sufficient to meet Bonneville's TPP policy. Bonneville measures RAR for both Power Services operations and Transmission Services operations.

Total Financial Reserves. "Total Financial Reserves" is a non-GAAP and unaudited metric that Bonneville uses to reflect current cash and cash equivalents. Bonneville uses the metric to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. Total Financial Reserves are composed of cash, cash equivalents, and special investments held in the Bonneville Fund, and amounts that Bonneville is authorized to borrow from the United States Treasury for capital expenditures that Bonneville has incurred but has not yet borrowed for ("Deferred Borrowing"), all of which are available to meet Bonneville's current expenditure needs. To reduce overall interest expense, Bonneville may delay borrowing from the United States Treasury until necessary from a cash flow perspective (which increases the Deferred Borrowing balance). Over time, Bonneville intends to borrow such Deferred Borrowing amounts from the United States Treasury. Total Financial Reserves is comprised of RAR and Reserves Not Available for Risk ("RNAR"). RNAR is a non-GAAP financial metric Bonneville uses as a measure of accumulated financial reserves that are not available for risk mitigation when establishing rates since such amounts are already committed for the payment of certain expenses. Total Financial Reserves are affected by numerous factors including revenues and expenses for the year, increases or decreases in cash and cash equivalents related to the timing of collections and payments, capital expenditures, and principal and interest payments to the United States Treasury. Bonneville does not use this metric in establishing rates; rather, Bonneville focuses on RAR. As of the end of Fiscal Year 2023, Total Financial Reserves were approximately $1.7 billion ($245 million of which represents Deferred Borrowing). See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments" and "—Fiscal Year 2023 Financial Results," and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025."

Days Liquidity on Hand. One metric that Bonneville uses to measure the amount of liquidity relative to its ability to meet operating expenses is "Days Liquidity on Hand." Bonneville measures this using the following equation: (i) RAR plus available United States Treasury Short-Term Credit Facility ($750 million) divided by (ii) Operating Expense (as described in footnote 1 in the "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments") divided by 360. This information is unaudited.

Bonneville's Fiscal Year-End Financial Reserves
Fiscal Years 2019-2023
(Unaudited)[1]
(Dollars in millions)

Fiscal Year	Total Financial Reserves	Reserves Available for Risk	United States Treasury Short-Term Credit Facility	Days Liquidity on Hand
2019	$773	$484	$750	222
2020	889	708	750	295
2021	1,056	825	750	284
2022	1,834	1,511	750	380
2023	1,727	1,287	750	258

(1) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Position Management and Derivative Instrument Activities and Policies

Bonneville has adopted risk management policies and organizational structures to systematically address the management of derivative instrument activities. Policies governing transacting are overseen by an internal risk committee composed of senior Bonneville executives.

Bonneville's policies allow the use of financial instruments such as commodity and interest rate futures, forwards, options, and swaps to manage Bonneville's risk to net revenue outcomes. Such policies do not authorize the use of financial instruments for purposes outside Bonneville-established strategies. Strategies are established in the context of portfolio management, as opposed to individual position/exposure management, and are subject to quantitatively-derived, hard position limits mathematically linked to Bonneville's financial metrics, such as TPP. Exceptions to established policies must be approved by Bonneville's internal risk committee before execution.

Bonneville's use of these various financial instruments is subject to regulation under the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). Dodd-Frank grants extensive discretion to applicable regulatory bodies, primarily the Commodities Futures Trading Commission ("CFTC") and the Securities and Exchange Commission ("SEC"), which have established rules regarding trading limits, and capital, reserve, and collateral requirements (primarily margin requirements).

In 2012, Bonneville approved a permanent and ongoing financial hedging program using power futures that do not require physical delivery. Such transactions require Bonneville to provide collateral through the posting of margin payments to cover the credit risk absorbed by the exchange. Margin payments can affect Bonneville's cash flows, especially if large margin payments are required. For exchange-traded power futures, failure to meet margin calls can subject a party's related agreements to immediate termination and the net mark-to-market value of the related agreements may become immediately due and payable. In contrast, Bonneville does not currently provide collateral to secure any of its related physical delivery power trading contract obligations, including over-the-counter physical delivery electric power transactions.

Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow

Streamflow is an important variable in Bonneville's financial performance because, in effect, it is the fuel for the hydroelectric facilities of the Federal System. The availability of hydroelectric generation affects Bonneville's purchased power costs as well as seasonal surplus energy sales. In periods of abundant hydroelectric generation Bonneville can avoid making "balancing" short-term power purchases to match loads. In periods of low hydroelectric generation, Bonneville's purchased power expense can increase to make such balancing purchases. Conversely, in periods of abundant hydroelectric generation Bonneville can obtain additional revenue from marketing seasonal surplus energy while in periods of low hydroelectric generation, such revenue can diminish. Bonneville's ratemaking, power and resource planning, financial operations, power operations, power marketing and risk management functions all take hydroelectric variability into account in their operations and have been doing so, in effect, since Bonneville's creation.

The relationship of operating revenues to operating expenses has been stable relative to wide variances in streamflow and hydro-generation. Much of this stability in revenues is attributable to the high proportion of power revenues that Bonneville derives from sales of firm power. Firm power is power expected to be produced by the Federal System under certain assumptions of Low Water Flows/Firm Water. See "POWER SERVICES—Description of the Generation Facilities of the Federal System—Federal Hydro-Generation." By contrast, Bonneville derives fewer revenues from seasonal surplus energy. In establishing the Final 2024-2025 Rates, Bonneville assumed that revenues from net seasonal surplus energy sales would average approximately $362 million per fiscal year of the rate period, assuming average streamflow. For reference, $362 million is approximately nine percent of Bonneville total operating revenues of approximately $4.3 billion (Fiscal Year 2023).

The following chart plots Bonneville's annual operating expense and operating revenues (as presented in the table entitled, "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments," see "—Statement of Non-Federal Debt Service Coverage") against Federal System streamflow in the same year. The streamflow data for the relevant year are expressed as a percentage of historical average streamflow. Bonneville believes that the relative stability of operating expense and operating revenue over a wide variety of annual streamflow conditions, particularly since 2002, reflects Bonneville's accommodation of the potential variability of streamflow in virtually all of Bonneville's major functions.

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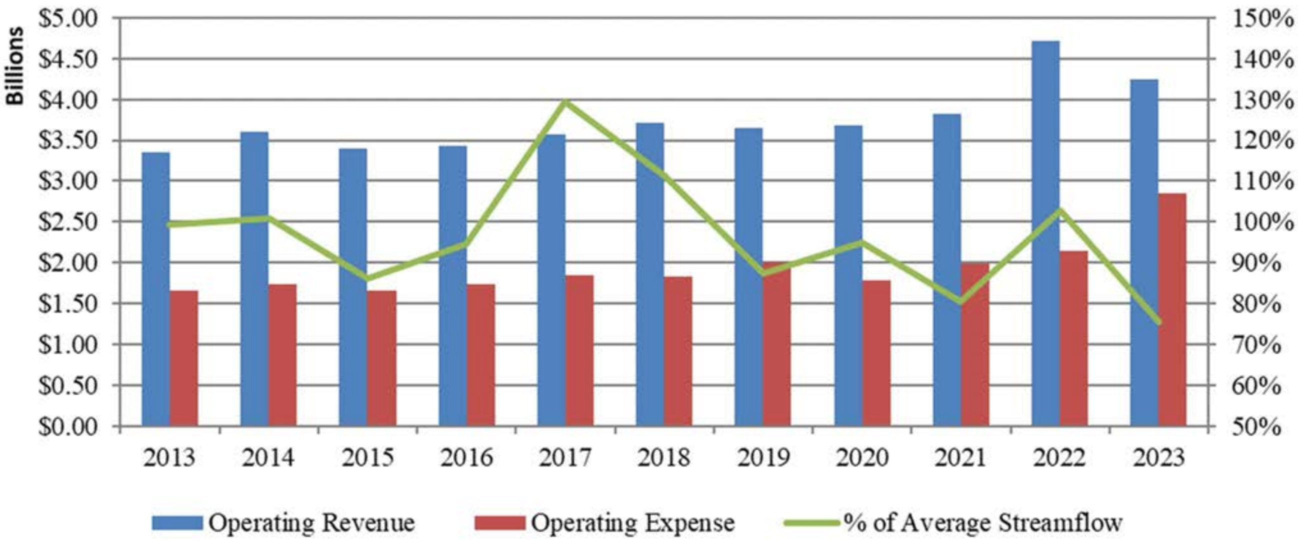
Historical Federal System Operating Revenue and Operating Expense
Compared to Historical Streamflow
($ in thousands)



In the preceding table, the streamflow data are based on the Federal System's Operating Year (August 1 – July 31) and the financial information is based on Bonneville's Fiscal Year (October 1 – September 30). "Operating Expense" is described in footnote 1 in the "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments."

Pension and Other Post-Retirement Benefits

Federal employees associated with the operation of the Federal System participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate in the Federal Employees Health and Benefit Program and the Federal Employee Group Life Insurance Program. All such post-retirement systems and programs are sponsored by the United States Office of Personnel Management; therefore, the accounts of the Federal System do not record any accumulated plan assets or liabilities related to the administration of such programs. Contribution amounts are paid by Bonneville to the United States Treasury and are recorded as expense during the year to which the payment relates. In Fiscal Year 2023, Bonneville made $39.1 million in post-retirement contributions.

Almost all of Energy Northwest's costs for its share of pension benefits relate to employment in connection with the Columbia Generating Station. To the extent that these costs arise in connection with the Energy Northwest Net Billed Projects, they have been and will be recovered under the Net Billing Agreements and borne by Bonneville. Such costs are included in "Non-Federal entities O&M—net billed" as reported in the Federal System Statement of Revenues and Expenses table below. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects."

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2021 through 2023 are set forth in the following "Federal System Statement of Revenues and Expenses (Unaudited)" table. Such data have been derived from the underlying financial records of the Federal System financial statements and differ therefrom in some respects in the categorization of certain costs. The audited Financial Statements of the Federal System (prepared in accordance with GAAP and provided as Appendix B-1 to the Official Statement) include accounts of Bonneville as well as those of the generating facilities that are located in the Region and owned by the Corps and Reclamation and for which Bonneville is the power marketing agency, and certain operations and maintenance costs of the Fish and Wildlife Service. Any discrepancies in totals for figures portrayed in this table are due to rounding.

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Federal System Statement of Revenues and Expenses (Unaudited)[14]

As of Sept. 30 – Dollars in millions	**2023**	**2022**	**2021**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities [1]	$1,924	$2,144	$2,130
Direct Service Industrial Customers	3	4	4
Northwest Investor-Owned Utilities	332	304	116
Sales outside the Northwest Region [2]	614	1,043	491
Book-outs [3]	(94)	(63)	(57)
Total Sales of Electric Power	2,779	3,432	2,684
Transmission Sales [4]	1,153	1,119	1,010
Fish Credits and other Revenues [5]	316	171	129
Total Operating Revenues	4,248	4,722	3,823
Operating Expenses:			
Bonneville O&M [6]	1,259	1,212	1,161
Purchased Power [3]	977	359	248
Corps, Reclamation, and Fish & Wildlife Service O&M [7]	457	410	404
Non-Federal entities O&M — net billed [8]	311	274	308
Non-Federal entities O&M — non-net billed [9]	35	33	30
Total Operations and Maintenance	3,039	2,288	2,151
Depreciation, Amortization and Accretion	849	841	826
Residential Exchange [10]	267	267	250
Total Operating Expenses	4,154	3,396	3,227
Net Operating Revenues	94	1,326	596
Interest Expense and Other Income/Expense:			
Appropriated Funds	42	41	44
Long-term debt – net billed	210	207	221
Long-term debt – non-net billed	191	224	226
Capitalization Adjustment [11]	(65)	(65)	(65)
Other (income)/expense, net[12]	14	(20)	(202)
Allowance for funds used during construction	(42)	(25)	(26)
Net Interest Expense and Other Income/Expense[13]	351	362	198
Net Revenues/(Expenses)	**$ (257)**	**$ 964**	**$ 398**
Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	8,676	10,861	9,667

(1) This customer group includes Preference Customers (municipalities, public utility districts, electric cooperatives, and tribal utilities in the Region) and federal agencies.

(2) In general, revenues from Sales outside the Northwest Region are derived from seasonal surplus energy and firm long-term sales. The availability of seasonal surplus energy that Bonneville has to market is highly

dependent upon the occurrence of streamflow in the Columbia River basin that is greater than would occur under Low Water Flows/Firm Water. In almost all years, except when streamflow is near Low Water Flows/Firm Water, the amount of seasonal surplus energy that Bonneville exports is greater than firm sales exports. Revenues from seasonal surplus energy sales are also affected by the prices Bonneville can obtain for the sale of energy in short-term energy markets, which is influenced by the cost other producers incur to generate energy and the price of fuel (in particular, natural gas) used to generate the energy.

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance associated with energy activities that are "booked out" (settled other than by the physical delivery of power) and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for book-outs has no effect on net revenues, cash flows, or margins.

(4) Bonneville obtains revenues from the provision of transmission and other related services.

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife payment credits (also referred to as "4(h)(10)(C) credits") that reduce Bonneville's United States Treasury repayment obligation. Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The amount of such credits was approximately $91 million, $112 million, and $258 million in Fiscal Years 2021, 2022, and 2023, respectively. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

(6) Bonneville O&M expenses include operations and maintenance expenditures for the Federal Transmission System, and other Bonneville functions such as Bonneville's power marketing, and fish and wildlife programs. Bonneville O&M as included herein reflects a mix of cash payments and accrued amounts, which, when aggregated with other line items presented herein, are consistent with amounts reported in the audited financial statements of the Federal System.

(7) Corps, Reclamation, and Fish and Wildlife Service O&M expenses include Federal System operations and maintenance expenditures of the Corps, Reclamation and the Fish and Wildlife Service. Amounts shown represent cash payments. An offsetting adjustment for accrued amounts is included in Bonneville O&M (see footnote (6) above).

(8) The Non-Federal entities O&M – net billed expense includes the operations and maintenance costs for generating facilities, the generating capability or output of which Bonneville has agreed to purchase under net billing agreements, which are capitalized contracts that cover the costs of Energy Northwest's terminated Project 1, terminated Project 3, and operating Columbia Generating Station, and EWEB's 30 percent ownership share of the terminated Trojan Nuclear Project.

(9) The Non-Federal entities O&M – non-net billed expense includes the operations and maintenance costs for generating facilities and the generating capability or output of which Bonneville has agreed to purchase under certain capitalized contracts, the costs of which are not net billed.

(10) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services" and "—Residential Exchange Program." Bonneville's aggregate payments to Regional IOUs with respect to the Residential Exchange Program for Fiscal Year 2012 through Fiscal Year 2028 were established under the 2012 Residential Exchange Program Settlement Agreement, dated July 26, 2011. In Fiscal Year 2023, the Residential Exchange Program payments were $267 million.

(11) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing Federal Appropriations Repayment Obligations under a federal law enacted in 1996.

(12) Other (income)/expense, net primarily includes dividend income and realized gains and losses associated with the Columbia Generating Station decommissioning and site restoration trust funds and losses incurred due to the early extinguishment of debt.

(13) Lease-Purchase Program is included in Net Interest Expense as reported in the audited financial statements of the Federal System. Amounts shown are calculated on an accrual basis.

(14) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Management's Discussion of Operating Results

Fiscal Year 2023

In Fiscal Year 2023, Bonneville made its scheduled United States Treasury payments on time and in full for the 40th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.7 billion, which is a decrease of approximately six percent from the prior fiscal year.

At the end of Fiscal Year 2023, aggregate Bonneville RAR was $1.3 billion, a decrease of approximately 15 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $923 million, a decrease of $321 million from the prior fiscal year-end balance of $1.2 billion, and RAR for Transmission Services operations was $363 million, an increase of $96 million from the prior fiscal year-end balance of $267 million.

In Fiscal Year 2023, Federal System net revenues were negative $257 million, a decrease of approximately $1.2 billion from net revenues of $964 million in Fiscal Year 2022.

In Fiscal Year 2023, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $4 billion, which is a decrease of approximately $595 million from consolidated gross sales of $4.6 billion in Fiscal Year 2022. Power Services' gross sales decreased $622 million, or approximately 18 percent, in Fiscal Year 2023 compared to Fiscal Year 2022, primarily due to: (i) a $344 million decrease in revenues from seasonal surplus energy sales due to lower streamflows and less hydroelectric generation when compared to Fiscal Year 2022 and (ii) a $278 million decrease in firm power sales due to a planned decrease in revenues as a result of the Power RDC (which reduced Fiscal Year 2023 firm sales by $350 million). A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2023 through July 2023 runoff volume at The Dalles Dam was 80 MAF, which is a decrease of 26 MAF over the same period in Fiscal Year 2022. The full Fiscal Year 2023 volume finished at 100 MAF, an increase of 37 MAF from Fiscal Year 2022, and below the historical average (1929-2018) of 134 MAF.

In Fiscal Year 2023, Transmission Services sales increased by $35 million compared to Fiscal Year 2022, primarily due to an increase in the sale of point-to-point long-term transmission service.

In Fiscal Year 2023, United States Treasury credits increased by $145 million compared to Fiscal Year 2022, primarily due to higher volumes of replacement power at higher market prices.

In Fiscal Year 2023, Operating expenses increased $758 million, or approximately 22 percent, compared to Fiscal Year 2022. In Fiscal Year 2023, Operations and maintenance expense increased $132 million, or six percent, compared to Fiscal Year 2022 primarily due to: (i) a $40 million increase in Columbia Generating Station plant costs since Fiscal Year 2023 was a refueling year (refueling and maintenance expense are typically higher in refueling years); (ii) a $32 million increase in Corps and Bureau expenditures primarily due to increased labor costs, (iii) a $23 million increase in energy conservation purchase due to additional work being completed in Fiscal Year 2023; (iv) an $11 million increase in Fish and Wildlife program expenditures primarily due to additional work performed in Fiscal Year 2023 when compared to the prior year; (v) a $9 million increase for reimbursable work performed for third parties due to an increase in large generator interconnection and line and load interconnection work performed in Fiscal Year 2023; (vi) a $6 million net increase related to an annual settlement paid to the Confederated Tribes of the Colville Reservation; (vii) a $4 million increase related to Transmission System Development Planning and Analysis; and (viii) a $7 million increase in various other Transmission Services and Power Services program costs primarily due to increases in personnel costs.

In Fiscal Year 2023, Purchased Power expense, including the effects of bookouts, increased $618 million, or approximately 172 percent, compared to Fiscal Year 2022 primarily due to: (i) a $585 million increase in Purchased Power due to dry conditions and lower water available for hydroelectric generation and higher market prices and (ii) a $33 million increase in the amount owed to British Columbia Hydro ("BC Hydro"), a Canadian electric utility owned by the province of British Columbia, under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2022.

In Fiscal Year 2023, Depreciation, Amortization, and Accretion increased $8 million compared to Fiscal Year 2022, primarily due to an $11 million increase in depreciation expense due to increased utility plant assets in service compared to the prior year. This increase was partially offset by a $4 million decrease in amortization expense due to asset retirements in Fiscal Year 2023.

In Fiscal Year 2023, total Net Interest Expense and Other Income/Expense decreased $11 million compared to Fiscal Year 2022, primarily due to an increase in interest income due to higher interest rates earned on short-term investments in United States Treasury securities compared to the prior year.

Fiscal Year 2022

In Fiscal Year 2022, Bonneville made its scheduled United States Treasury payments on time and in full for the 39th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.8 billion, which is an increase of approximately 74 percent from the prior fiscal year.

At the end of Fiscal Year 2022, aggregate Bonneville RAR was $1.5 billion, an increase of approximately 83 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $1.2 billion, an increase of $628 million from the prior fiscal year-end balance of $617 million, and RAR for Transmission Services operations was $267 million, an increase of $58 million from the prior fiscal year-end balance of $209 million.

In Fiscal Year 2022, Federal System net revenues were $964 million, an increase of approximately $566 million from net revenues of $398 million in Fiscal Year 2021.

In Fiscal Year 2022, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $4.6 billion, which is an increase of approximately $858 million from consolidated gross sales of $3.7 billion in Fiscal Year 2021. Power Services' gross sales increased $754 million, or approximately 28 percent, in Fiscal Year 2022 compared to Fiscal Year 2021, primarily due to an increase in revenues from seasonal surplus energy sales due to higher market prices than forecast in the rate case. A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2022 through July 2022 runoff volume at The Dalles Dam was 106 MAF, which is an increase of 24 MAF over the same period in Fiscal Year 2021. The full Fiscal Year 2022 volume finished at 137 MAF, an increase of 30 MAF from Fiscal Year 2021, and above the historical average of 134 MAF.

In Fiscal Year 2022, Transmission Services sales increased $104 million compared to Fiscal Year 2021, primarily due to an increase in the sale of point-to-point long-term transmission service.

In Fiscal Year 2022, United States Treasury credits increased by $22 million compared to Fiscal Year 2021, primarily due to higher volumes of replacement power at higher market prices.

In Fiscal Year 2022, Operating expense increased $168 million, or approximately five percent, compared to Fiscal Year 2021. In Fiscal Year 2022, Operations and maintenance expense increased $43 million, or two percent, compared to Fiscal Year 2021 primarily due to: (i) a $25 million increase in enterprise services general and administrative expenses to support various Power Services and Transmission Services programs; (ii) a $17 million scheduled increase to Residential Exchange Program costs, (iii) a $17 million increase in settlement charges related to Bonneville's participation in Cal-ISO's Western Energy Imbalance Market ("EIM"), a real-time bulk power trading market system that automatically finds the lowest-cost energy to serve real-time customer demand (resolving imbalances while maintaining reliability) across a wide geographic area (under the EIM, utilities maintain control over their assets and remain responsible for balancing requirements while sharing in the costs and benefits that the market produces for participants); (iv) a $15 million increase in Corps expenditures primarily due to fish mitigation studies and higher labor and materials costs due to inflation; (v) an $11 million increase in third-party wheeling expenses due to increased power sales and the need to transmit more electric power to customers not directly connected to the Federal Transmission system in Fiscal Year 2022; and (vi) a $10 million net increase to various other Transmission Services and Power Services program costs. The various increases in Operations and maintenance expense were partially offset by: (i) a $37 million decrease in Columbia Generating Station plant costs since Fiscal Year 2022 was not a refueling year (refueling and maintenance expense are typically higher in refueling years) and (ii) a $15 million decrease in energy conservation expenses due to less work performed in Fiscal Year 2022 when compared to Fiscal Year 2021.

In Fiscal Year 2022, Purchased Power expense, including the effects of bookouts, increased $111 million, or approximately 45 percent, compared to Fiscal Year 2021 primarily due to: (i) a $101 million increase in Purchased Power due to higher market prices and (ii) a $10 million increase in the amount owed to British Columbia Hydro ("BC Hydro"), a Canadian electric utility owned by the province of British Columbia, under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2021.

In Fiscal Year 2022, Depreciation, Amortization, and Accretion increased $14 million compared to Fiscal Year 2021, primarily due to an $8 million increase in amortization related to the Columbia River Fish Mitigation program.

In Fiscal Year 2022, total Net Interest Expense and Other Income/Expense increased $164 million compared to Fiscal Year 2021, primarily due to a $182 million decrease in Other Income.

Fiscal Year 2021

In Fiscal Year 2021, Bonneville made its scheduled United States Treasury payments on time and in full for the 38th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.056 billion, which is an increase of approximately 19 percent from the prior fiscal year.

At the end of Fiscal Year 2021, aggregate Bonneville RAR was $825 million, an increase of approximately 17 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $617 million, an increase of $181 million from the prior fiscal year-end balance of $435 million, and RAR for Transmission Services operations was $208 million, a decrease of $64 million from the prior fiscal year-end balance of $273 million.

In Fiscal Year 2021, Federal System net revenues were $398 million, an increase of approximately $152 million from net revenues of $246 million in Fiscal Year 2020.

In Fiscal Year 2021, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $3.7 billion, which is an increase of approximately $164 million from consolidated gross sales of $3.5 billion in Fiscal Year 2020. Power Services' gross sales increased $136 million, or approximately five percent, in Fiscal Year 2021 compared to Fiscal Year 2020, primarily due to an increase in revenues from seasonal surplus sales due to higher short-term energy market prices that Bonneville was able to obtain for the sale of seasonal surplus energy. A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January through July 2021 runoff volume at The Dalles Dam was 82 MAF. The full Fiscal Year 2021 volume finished at 107 MAF, a decrease of 19 MAF from Fiscal Year 2020, and below the historical average of 134 MAF.

In Fiscal Year 2021, Transmission Services sales increased $28 million compared to Fiscal Year 2020, primarily due to an increase in the sale of point-to-point long-term transmission service.

In Fiscal Year 2021, United States Treasury credits decreased $5 million compared to Fiscal Year 2020, primarily due to lower replacement power purchases required for fish and wildlife mitigation purposes. For more details, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife."

In Fiscal Year 2021, Operating expense increased $219 million, or approximately seven percent, compared to Fiscal Year 2020. In Fiscal Year 2021, Operations and maintenance expense increased $87 million, or four percent, from the prior fiscal year primarily due to a $51 million increase in Columbia Generating Station plant costs since Fiscal Year

2021 was a refueling year (refueling and maintenance expense are typically higher in refueling years). In Fiscal Year 2021, Purchased Power expense, including the effects of bookouts, increased $125 million, or approximately 101 percent, compared to Fiscal Year 2020 mainly due to: (i) an $80 million increase in Purchased Power that Bonneville needed to serve its loads in Fiscal Year 2021 compared to periods of extremely cold weather in Fiscal Year 2020 that increased demand for energy during times of high market prices and limited supply and (ii) a $45 million increase in the amount owed to BC Hydro under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2020.

In Fiscal Year 2021, Depreciation, Amortization, and Accretion increased $8 million compared to Fiscal Year 2020, primarily due to increases in the amortization related to capital additions at the Columbia Generating Station.

In Fiscal Year 2021, total Net Interest Expense and Other Income/Expense, decreased $232 million compared to Fiscal Year 2020, primarily due to a $195 million increase in Other Income. The primary driver for this increase was a $163 million increase in dividends and net realized gains on investments held in the Columbia Generating Station decommissioning and restoration trust funds. For more details regarding the Columbia Generating Station decommissioning and restoration trust funds, see Appendix B-1 to the Official Statement (Note 6 to the Fiscal Year 2023 Audited Financial Statements).

Statement of Non-Federal Debt Service Coverage

The "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments" below uses the "Federal System Statement of Revenues and Expenses (Unaudited)" to develop a non-federal project debt service coverage ratio ("Non-Federal Debt Service Coverage Ratio"), which demonstrates how many times total non-federal project debt service is covered by net funds available for non-federal project debt service. Net funds available for non-federal debt service is defined as total operating revenues less operating expenses. Net funds available for non-federal project debt service less total non-federal project debt service yields the amount available for payment to the United States Treasury. This Non-Federal Debt Service Coverage Ratio does not reflect the actual priority of payments or distinctions between cash payments and credits under Bonneville's net billing obligations under the Net Billing Agreements. Any discrepancies in totals for figures portrayed in this table are due to rounding.

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Statement of Non-Federal Debt Service Coverage and United States Treasury Payments (Unaudited)[13]

As of Sept. 30 – Dollars in millions	2023	2022	2021
Total Operating Revenues	$4,248	$4,722	$3,823
Less: Operating Expenses[1]	2,848	2,144	1,996
Net Funds Available to meet Non-Federal Debt Service Obligations	1,400	2,578	1,827
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects[2]	229	194	171
Lease-Purchase Program[3]	130	132	134
Electric Power Prepayments [4]	31	31	31
Total Non-Federal Debt Service Obligations	390	357	336
Revenue Available for Treasury	$1,010	$2,221	$1,491
Non-Federal Debt Service Coverage Ratio[5]	3.6x	7.2x	5.4x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[6]	1.3x	1.9x	1.6x
Amount Allocated for Payment to Treasury[7]:			
Corps and Reclamation O&M[8]	$457	$410	$404
Net Interest Expense and Other Income/Expense[9]	351	362	198
Non-Federal Projects[2, 9]	(198)	(187)	(24)
Lease-Purchase Program[3, 9]	(58)	(59)	(61)
Electric Power Prepayments[4, 9]	(7)	(8)	(9)
Capitalization Adjustment[10]	65	65	65
Allowance for Funds Used During Construction [11]	25	15	12
Amortization of Federal Principal[12]	741	694	806
Total Amount Allocated for Payment to Treasury[7]	$1,376	$1,292	$1,391

(1) Operating Expenses include the following items from the Federal System Statement of Revenues and Expenses: Bonneville O&M, Purchased Power, Non-Federal entities O&M-net billed, Non-Federal entities O&M non-net-billed, and the Residential Exchange Program. Operating Expenses do not include certain payments to the Corps and Reclamation. Treatment of the Corps, Reclamation, and Fish and Wildlife Service operating expense is described in "—Direct Funding of Federal System Operations and Maintenance Expense."

(2) Includes debt service (principal and interest) for generating resources acquired by Bonneville under Net Billing Agreements or other capitalized contracts. Non-net billed debt service amounted to $9 million, $9 million, and $9 million for Fiscal Years 2021, 2022, and 2023 respectively. To reconcile Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) the interest expense portion of the Non-Federal Projects as shown here is a reduction of Amount Allocated for Payment to Treasury.

(3) To reconcile Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) the interest expense portion of the Lease-Purchase Program included here is a reduction of Amount Allocated for Payment to Treasury. A portion of the Lease-Purchase Program Debt Service includes amounts related to the repayment of principal on maturing bonds.

(4) To reconcile Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) the interest expense portion of the Electric Power Prepayments included here is a reduction of Amount Allocated for Payment to Treasury. In Fiscal Year 2013, Bonneville received $340 million from certain Preference Customers as one-time prepayments of portions of their future power bills through Fiscal Year 2028. In return the customers will receive credits in future power bills. The aggregate amount of the credits is $2.55 million per month through Fiscal Year 2028. In Fiscal Year 2023, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $31 million. Of this amount, $7 million is accounted for as Net Interest Expense and $24 million is accounted for as the repayment of principal. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments."

(5) The "Non-Federal Debt Service Coverage Ratio" is defined as follows:

$$\frac{\textbf{Total Operating Revenues-Operating Expense (Footnote 1)}}{\textbf{Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments}}$$

(6) The "Non-Federal Debt Service plus Operating Expense Coverage Ratio" is defined as follows:

$$\frac{\textbf{Total Operating Revenues}}{\textbf{Operating Expense (Footnote 1) + Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments}}$$

(7) In contrast to the "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2021, 2022, and 2023 were $1.05 billion, $951 million, and $1.02 billion respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation, and Fish and Wildlife Service as portrayed under "Corps and Reclamation O&M." See "—Direct Funding of Federal System Operations and Maintenance Expense."

(8) Amounts shown are calculated on a cash basis and include direct operations and maintenance payments to the Corps, Reclamation, and Fish and Wildlife Service for Fiscal Years 2021, 2022, and 2023. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(9) Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) includes certain interest associated with obligations to Non-Federal entities. Amounts shown are calculated on an accrual basis.

(10) The capitalization adjustment is included in net interest expense but is not part of Bonneville's payment to the United States Treasury.

(11) The Allowance for Funds Used During Construction includes, among other things, Bonneville's portion of the interest during the construction period for Federal System investments funded by borrowings from the United States Treasury. For clarity, none of the related interest expense for the Lease-Purchase Program is reflected in Allowance for Funds Used During Construction.

(12) Regional Cooperation Debt actions enabled Bonneville to prepay $401 million in Federal Obligations in Fiscal Year 2023, $334 million in Fiscal Year 2022, and $332 million in Fiscal Year 2021, in addition to the amounts otherwise scheduled for repayment in Bonneville's rates. The effect of these prepayments and the extension of Energy Northwest debt resulted in atypically high Non-Federal Debt Service Coverage Ratios.

(13) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Management's Discussion of Unaudited Results for the Six Months ended March 31, 2024

Total operating revenues were $2.5 billion through the second quarter of Fiscal Year 2024 ("Fiscal Year 2024 Second Quarter"), an increase of $208 million as compared to operating revenues of $2.3 billion for the six months ended March 31, 2023 ("Fiscal Year 2023 Second Quarter"). Consolidated gross sales for Power and Transmission Services, including the effect of bookouts, were $2.2 billion through Fiscal Year 2024 Second Quarter, an increase of $116 million through Fiscal Year 2024 Second Quarter compared to consolidated gross sales of $2 billion through Fiscal Year 2023 Second Quarter. ("Bookouts" are a reflection of accounting guidance associated with energy activities that are settled other than by the physical delivery of power and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for book-outs has no effect on net revenues, cash flows, or margins.)

Power Services gross sales, including the effect of bookouts, were $1.6 billion through Fiscal Year 2024 Second Quarter, an increase of $49 million as compared to Power Services gross sales, including the effect of bookouts, of $1.5 billion through Fiscal Year 2023 Second Quarter. Revenues from firm power sales increased by $38 million through Fiscal Year 2024 Second Quarter as compared to revenues from firm power sales through Fiscal Year 2023 Second Quarter primarily due to a lower amount of planned Power Reserves Distribution Clause rate reductions that were applied as a credit to Power rates through Fiscal Year 2024 Second Quarter, which were $72 million, when compared to the $138 million of Power Reserves Distribution Clause rate reductions that were applied as a credit to Power rates through Fiscal Year 2023 Second Quarter.

Transmission sales were $612 million through Fiscal Year 2024 Second Quarter, an increase of $67 million as compared to Transmission sales of $545 million through Fiscal Year 2023 Second Quarter. The increase in Transmission sales was primarily related to: (i) a $48 million increase in EIM revenues related to the January 2024 cold snap and (ii) a $19 million increase related to additional network integration, intertie, and ancillary services revenues. United States Treasury credits for fish and wildlife mitigation increased by $64 million due to decreased streamflow through Fiscal Year 2024 Second Quarter which led to an increase in purchased power expense due to higher volumes of purchases at higher market prices.

Through Fiscal Year 2024 Second Quarter, total operating expenses were $2.5 billion, a $208 million increase when compared to total operating expenses of $2.3 billion through Fiscal Year 2023 Second Quarter.

Operations and maintenance expense increased by $37 million primarily due to: (i) a $23 million increase in EIM settlement charges due to the January 2024 cold snap, (ii) a $10 million increase in Transmission maintenance expenses due to increased maintenance performed throughout various asset management programs; and (iii) a $21 million net increase to various other Transmission Services and Power Services program costs primarily related to increases in personnel costs. Purchased power expense, including the effects of bookouts, increased by $160 million primarily due to a $241 million increase in power purchases due to the January 2024 cold snap resulting in higher market prices that Bonneville paid for its purchased power during cold weather experienced in Fiscal Year 2024 Second Quarter. The increase in power purchases is partially offset by an $82 million decrease in the amount owed to BC Hydro under certain water storage agreements. The amount that Bonneville owes or receives from BC Hydro under the water storage agreements is determined by how much water BC Hydro releases from its storage area in a particular year.

Depreciation, amortization and accretion increased by $11 million through Fiscal Year 2024 Second Quarter when compared to Fiscal Year 2023 Second Quarter, primarily due to an increase in utility plant assets in service.

Total Interest Expense and Other Income, Net, decreased $30 million in Fiscal Year 2024 Second Quarter when compared to the same period in Fiscal Year 2023. Interest Expense increased by $3 million primarily due to an increase in debt outstanding to the United States Treasury. Interest Income decreased by $1 million in Fiscal Year 2024 Second Quarter when compared to the same period in Fiscal Year 2023 due to reduced short-term investments in United States Treasury securities and slightly lower interest rates earned on such investments.

Other, Net decreased by $29 million through Fiscal Year 2024 Second Quarter when compared to Fiscal Year 2023 Second Quarter, primarily due to: (i) a $26 million decrease to net expenses related to the Boardman to Hemingway and debt extinguishment transactions that occurred in Fiscal Year 2023 and (ii) a $2 million increase in dividends received on investments held in the Energy Northwest nuclear decommissioning and site restoration funds.

For further information regarding Fiscal Year 2024 Second Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE SIX MONTHS ENDED MARCH 31, 2024."

BONNEVILLE LITIGATION

Bonneville is involved in the following matters in addition to the litigation described elsewhere in this Appendix A:

Columbia River ESA Litigation

Since 2001, NOAA Fisheries and the Action Agencies have been involved in continuous litigation with the National Wildlife Federation ("NWF") and other plaintiffs in the District Court over a succession of biological opinions relating to listed anadromous salmonid species of the Columbia and Snake rivers. This litigation began with a challenge to the 2000 Columbia River System Biological Opinion and has resulted in a series of revised biological opinions (including the 2004 Biological Opinion, the 2008 Biological Opinion, the 2010 Supplemental Biological Opinion, and the 2014 Supplemental Biological Opinion, each of which attempted to correct the deficiencies identified by the court) and subsequent challenges under the ESA, the APA, and NEPA.

In January 2014, NOAA Fisheries issued the 2014 Columbia River System Supplemental Biological Opinion. In February 2014, the Action Agencies each signed a decision document to implement the biological opinion. In May 2014, American Rivers and other plaintiffs filed a petition in the Ninth Circuit Court challenging Bonneville's record of decision. In July 2014, NWF and other plaintiffs challenged NOAA Fisheries' biological opinion and the Corps' and Reclamation's decision documents in District Court, and the State of Oregon intervened as a plaintiff in this litigation in October 2014. In both the District Court and Ninth Circuit Court actions, plaintiffs alleged that the 2014 Columbia River System Supplemental Biological Opinion and related decisions violate certain provisions of the ESA, NEPA, and the APA. These lawsuits were similar to previous challenges of past biological opinions, with the exception of one additional claim under NEPA challenging the Action Agencies' failure to prepare a new environmental impact statement for their adoption and implementation of the Reasonable and Prudent Alternative actions in the biological opinion. The Ninth Circuit Court originally issued an order staying the petition against Bonneville pending resolution of the District Court action. Shortly after the issuance by the District Court of the May 4, 2016 order described immediately below, the lawsuit in the Ninth Circuit Court was voluntarily dismissed.

On May 4, 2016, the District Court issued a ruling on the ESA challenges to the 2014 Columbia River System Supplemental Biological Opinion and the NEPA challenge. The District Court concluded that the Corps and Reclamation violated NEPA and identified a number of deficiencies with the 2014 Columbia River System Supplemental Biological Opinion, including that the approach used by NOAA Fisheries to determine whether the listed species "are trending toward recovery" is arbitrary and capricious, that the 2014 Columbia River System Supplemental Biological Opinion relies on habitat restoration benefits that "are too uncertain and do not allow any margin of error," and that the 2014 Columbia River System Supplemental Biological Opinion "fails to properly analyze the effects of climate change." See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On July 6, 2016, the District Court issued an order directing that a new biological opinion under the ESA be prepared on or before December 31, 2018, a new environmental impact statement under NEPA be prepared on or before March 26, 2021, and that the federal agencies' records of decision documenting decisions on how to implement the ESA, which will be informed by analyses provided in the environmental impact statement, shall be issued on or before September 24, 2021. On April 17, 2018, the District Court issued an order adjusting the deadline for the new biological opinion and environmental impact statement to March 26, 2021. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On January 9, 2017, plaintiffs filed requests for injunctive relief with the District Court seeking increased spring spill at eight Federal Snake River and Columbia River System dams and a halt to spending by the Corps of Engineers on certain ongoing and future capital projects at the four lower Snake River dams. In April 2017, the District Court issued an opinion and order granting in part and denying in part the motions for injunction with respect to spill and capital project funding. In its April 2017 ruling, the District Court ordered "increased spill" but delayed implementation of changes to system operations "until the spring 2018 migration season" in order to allow time for the parties to develop a "spill implementation plan and proposed injunction order," either through consensus or by court resolution following subsequent briefings and hearings. On June 2, 2017, the federal defendants filed a notice of appeal from the April 3, 2017 initial injunction ruling. On January 8, 2018, the District Court issued a final order directing increased spill for the spring 2018 fish passage season (approximately April-June 2018) at all eight Federal Snake River and Columbia River System dams identified in the injunction motions and certain fish monitoring actions.

The Ninth Circuit Court issued an opinion on April 2, 2018, affirming the District Court's spill and fish monitoring injunctions. Spill for fish passage under the District Court's injunction order began at the eight Snake and Columbia River Federal System dams in April 2018.

On December 14, 2018, Action Agencies, defendant intervenor State of Washington, plaintiff the State of Oregon and amicus the Nez Perce Tribe entered into an agreement in which the Action Agencies agreed to specified spring spill operations in 2019 and 2020, and a cap on the related costs of the agreed spring spill operations borne by Bonneville, in exchange for a pause in litigation on the biological opinion. The agreement set the costs to Bonneville of the 2019 and 2020 spring spill at no more than the cost of 2018 spring spill operations. Because the agreement changed the proposed action, NOAA Fisheries issued a new biological opinion (referred to herein as the "2019 Columbia River System Biological Opinion") incorporating the agreed to spring spill operations, effective April 1, 2019 until a new action could be adopted through records of decision related to the ongoing CRSO NEPA process.

On September 28, 2020, the Action Agencies signed a joint record of decision adopting the Preferred Alternative in the Final CRSO EIS and adopting the 2020 Columbia River System Biological Opinions. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

In December 2020, a coalition of fishing and environmental groups and two Indian tribes filed complaints in the Ninth Circuit Court challenging Bonneville's CRSO Environmental Impact Statement Record of Decision alleging that Bonneville's decision violated certain provisions of the ESA, NEPA, APA, and the Northwest Power Act. These cases were consolidated on January 13, 2021. On August 18, 2021 Bonneville filed a certified index and certification for administrative record. On January 19, 2021, the environmental groups filed a motion for leave to file a supplemental complaint in the District Court case alleging that the Final CRSO EIS, the 2020 Columbia River System Biological Opinions, and related decisions by the Corps and Reclamation violate certain provisions of the ESA and NEPA, as well as the APA and the Northwest Power Act, as well as challenging NOAA Fisheries under the ESA, which was granted the same day. Four Indian tribes and the states of Oregon, Idaho, and Montana have intervened in the District Court litigation, and the state of Washington as well as several Indian tribes are involved as unaligned amicus curiae. There is substantial overlap between the Ninth Circuit Court and District Court cases. On August 24, 2021, the federal government received a letter from NWF requesting discussions on a resolution of the cases without continued litigation by first addressing 2022 operations and then holding discussions on a long-term comprehensive solution. The parties sought an extension to the briefing schedule from the District Court to allow for these discussions to occur. The federal government entered into discussions with NWF, the State of Oregon, and the Nez Perce Tribe on October 1, 2021. The federal government agreed to 2022 operations with these entities and filed a motion on October 21, 2021 with the District Court to stay proceedings for the preliminary injunction and summary judgment motions and provide notice of the agreed upon 2022 operations. One plaintiff-aligned amicus filed an objection to the stay. The District Court granted the stay until July 31, 2022, denied the objection, denied without prejudice and leave to renew the preliminary injunction motions, and ordered a joint status report on the long-term discussions by July 31, 2022. The Ninth Circuit granted administrative closure of that case to align with the stay in the District Court. The litigation stay was extended until August 31, 2023 at the District Court and until September 8, 2023 in the Ninth Circuit. As part of the continued stay, the parties agreed on 2023 fish passage operations, which are largely consistent with 2022 fish passage operations. The parties have filed two status reports with the District Court (on November 2, 2022 and January 31, 2023) in compliance with the District Court's stay order and one status update with the Ninth Circuit Court (on March 15, 2023).

On September 28, 2023, the Department of Justice filed a motion to voluntarily dismiss certain claims brought by the Coeur d'Alene Tribe and Spokane Tribe of Indians based on a 20-year mediated settlement agreement entered into by Bonneville with other federal agencies. In this stay agreement Bonneville committed to fund $200 million in annual payments of $10 million over 20 years, among other things, in exchange for the dismissal of these complaints. The District Court granted this motion on September 28, 2023. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

On October 31, 2023, the Department of Justice filed a notice with the District Court providing an update that the federal defendants and certain participants in this litigation had developed a proposed package of actions and commitments. This proposed package was discussed with the other regional sovereigns and litigation parties through a confidential conferral process. Based on the December 2023 Agreement, the federal defendants, the National Wildlife Federation Plaintiffs and the states of Oregon and Washington, and the Yakama Nation, the Nez Perce Tribe, the Confederated Tribes of the Warm Springs Indian Reservation, and the Confederated Tribes of the Umatilla Indian Reservation, filed a joint stay motion asking the District Court to pause the litigation for five years, through December 2028. Subsequent to filing the joint stay motion, the states of Idaho and Montana, the Public Power Council, Northwest River Partners and Inland Ports and Navigation Group filed oppositions to the stay motion. On February 8, 2024, the U.S. District Court for the District of Oregon granted a stay through December 13, 2028 (with potential for an additional five years), and on February 23, 2024, the U.S. Court of Appeals for the Ninth Circuit dismissed without prejudice litigation regarding the CRSO EIS and associated consultation.

There are three petitions currently filed with the Ninth Circuit Court challenging Bonneville's authority under the Northwest Power Act to sign on to the December 2023 Agreement. Bonneville is unable to predict the outcome of this litigation or its potential impact on the December 2023 Agreement and associated spill operations.

EPA Clean Water Act Litigation

On February 23, 2017, Columbia Riverkeeper and other plaintiffs filed suit against the EPA in Washington Federal District Court in Seattle alleging violations of the Clean Water Act – Section 303(d) and the APA. The Washington Federal District Court granted, in part, the plaintiffs' claims directing EPA to approve or disapprove of what the Washington Federal District Court determined was a constructive submission of a Total Maximum Daily Allowance ("TMDL") for temperature in the Columbia and Snake Rivers by Oregon and Washington within 30 days of the ruling. The Washington Federal District Court then determined that if EPA disapproves of the constructive TMDL it must issue a new TMDL 30 days from that date. The United States appealed the Washington Federal District Court's ruling to the Ninth Circuit Court and received a stay on its ruling. EPA and the plaintiffs agreed to an expedited review of the case by the Ninth Circuit Court. EPA filed its opening brief on April 12, 2019. Plaintiffs' answer was filed on May 10, 2019 and EPA's reply was filed on June 7, 2019. Oral arguments were held in the Ninth Circuit Court case in August 2019. On December 20, 2019, the Ninth Circuit issued its opinion affirming the district court's decision that the states had constructively submitted a temperature TMDL, which triggered EPA's duty to act under the Clean Water Act and develop and issue a temperature TMDL. The EPA issued the temperature TMDL for public review and comment on May 18, 2020. After reviewing and considering comments, the EPA reissued the TMDL on August 13, 2021. As part of the Clean Water Act regulations on TMDLs, EPA transmitted the re-issued TMDL to the states of Oregon and Washington, so the states could begin developing implementation plans. Currently, the Oregon Department of Environmental Quality and Washington Department of Ecology have not begun developing the implementation plans, but Bonneville will work closely with these state agencies once this process begins.

Bonneville is unable to predict the outcome of these implementation plans but it could lead to potential changes in the operation and configuration of the Federal System Hydroelectric Projects.

Holiday Farm Fire Litigation

Over the Labor Day holiday weekend in September 2020, what was later known as the HFF started in the vicinity of Eugene, Oregon. The fire burned over 170,000 acres, causing property damage, personal injuries, and one known death. As a result of the HFF, and pursuant to the requirements of Federal Tort Claims Act ("FTCA"), Bonneville received more than 2,000 administrative tort claims, totaling more than $2 billion.

Various law firms, representing plaintiffs affected by the HFF, have recently filed federal complaints. One of the law firms also filed an inverse condemnation (5th Amendment taking) complaint in the United States Court of Federal Claims in Washington DC.

It is unlikely that any further inverse condemnation complaints will be filed. Three complaints have been filed under the FTCA in United States District Court, and it is likely that more will follow.

Federal Tort Claims Act

Plaintiffs allege that Bonneville had a duty to operate, monitor, maintain, and repair its electric utility infrastructures to ensure that it did not cause fires. This duty included not continuing to energize powerlines during periods of fire risk to prevent fires and to allow first responders to safely access areas to put out fires.

Two Bonneville electric utility customers, Lane Electric Cooperative (“LEC”) and Eugene Water & Electric Board (“EWEB”), are also defendants, joined as indispensable parties because of their involvement in the HFF.

In January and February of 2024 three separate suits under the FTCA were filed in the United States District Court for the District of Oregon. No response has been filed to date by the United States. All settlements or court judgments from tort claims are paid by the United States Judgment Fund, not the Bonneville Fund.

Inverse Condemnation

On December 12, 2023, the U.S Department of Justice was served with an inverse condemnation claim related to the HFF. The complaint is based on the same operative facts as the claims under the FTCA. Plaintiffs in the Inverse Condemnation suit are a subset of the plaintiffs in the FTCA suits and many of the claims related to property damage overlap with the FTCA claims.

The complaint alleges that the HFF resulted in a taking of plaintiffs’ property without just compensation and is therefore compensable under the 5th Amendment of the United States Constitution. Like the FTCA suits described above, the Inverse Condemnation complaint also references LEC and EWEB.

On February 14, 2024, the United States filed a motion to dismiss this case. On April 10, 2024, plaintiffs filed their response to the motion to dismiss. The United States’ reply is due on May 1, 2024. Bonneville is unable to predict whether any settlements or judgments arising from this suit would be paid from the United States Judgment Fund or the Bonneville Fund.

Fiscal Year 2022-2023 Rates Challenge

On June 16, 2022, Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United filed suit against Bonneville in the Ninth Circuit Court petitioning for review of Bonneville’s decision adopting power and transmission rates for Fiscal Year 2022 and Fiscal Year 2023. Petitioners sought: (i) a decision to set aside Bonneville’s final rate decision and remand to Bonneville with instructions to set new rates in accordance with a proper construction of the Northwest Power Act and (ii) an order requiring Bonneville to provide increased funding for fish and wildlife mitigation efforts during the remand period. Briefing concluded on February 3, 2023. Oral argument took place on June 8, 2023. The parties jointly filed supplemental briefs on June 23, 2023. On October 19, 2023, the Ninth Circuit Court affirmed Bonneville’s decision adopting power and transmission rates for Fiscal Year 2022 and Fiscal Year 2023 and denied the petition. The petitioners did not seek rehearing and this case is now closed.

Fiscal Year 2022 Power RDC Challenge

Based on the Power Services’ RAR balance of $1.2 billion at September 30, 2022 and total RAR of $1.5 billion at September 30, 2022, a Power RDC triggered in the amount of $500 million for application to certain Power Services rate levels in Fiscal Year 2023. On January 6, 2023, the Administrator determined that 70 percent or $350 million of the Power RDC would be applied to reduce Power rates from December 2022 through September 2023. Credits were applied to power customer bills through September 2023. In addition to the rate reduction implemented in Fiscal Year 2023, $100 million of the Power RDC amount was held in Total Financial Reserves for debt reduction in Fiscal Year 2023 and $50 million was held in Total Financial Reserves to fund certain fish and wildlife expenses on an accelerated basis (in advance of when such expenditures were originally expected to be made).

On April 5, 2023, Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United filed suit against Bonneville in the Ninth Circuit Court petitioning for review of Bonneville’s Fiscal Year 2022 Power RDC decision. Petitioners seek the same relief as in the Fiscal Year 2022-2023 Rates Challenge discussed above: (i) a decision to set aside Bonneville's Fiscal Year 2022 Power RDC decision and remand to Bonneville with instructions to revisit the decision in a manner that complies with Bonneville's duties to fish and wildlife under the Northwest Power Act and (ii) other declaratory and injunctive relief as necessary to remedy their injuries including an order requiring Bonneville to provide increased funding for fish and wildlife mitigation efforts during the remand period.

In April 2023, the Public Power Council, Northwest Requirements Utilities, and Alliance of Western Energy Consumers moved to intervene in this case. On May 11, 2023, the Ninth Circuit Court issued an order administratively closing this case until November 13, 2023 and suspended the briefing schedule pending the outcome of the Fiscal Year 2022-2023 Rates challenge. The case has been reopened and petitioners filed their opening brief on March 15, 2024. Bonneville's answering brief was filed on May 3, 2024. Briefing is scheduled to conclude on June 7, 2024 with petitioners' reply brief.

Fiscal Year 2023 Power RDC Challenge

On March 18, 2024, Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United filed suit against Bonneville in the Ninth Circuit Court petitioning for review of Bonneville's Fiscal Year 2023 Power RDC decision, which was issued on December 23, 2023. For details related to the Fiscal Year 2023 Power RDC, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Bonneville Power and Transmission Rates Developments." Petitioners seek: (i) a decision to set aside Bonneville's Fiscal Year 2023 Power RDC decision and remand to Bonneville with instructions to revisit the decision in a manner that complies with Bonneville's duties to fish and wildlife under the Northwest Power Act and (ii) other declaratory and injunctive relief as necessary to remedy their injuries including an order requiring Bonneville to provide increased funding for fish and wildlife mitigation efforts during the remand period.

In April 2024, the Public Power Council, Northwest Requirements Utilities, and Alliance of Western Energy Consumers moved to intervene in this case. Petitioners' opening brief is due on June 28, 2024. Bonneville's answering brief and any intervenor briefs are due on August 16, 2024. Briefing is scheduled to conclude on September 6, 2024 with petitioners' reply brief.

Rates Litigation Generally

Bonneville's rates are frequently the subject of litigation in the Ninth Circuit Court. Most of the litigation involves claims that Bonneville's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record or are arbitrary and capricious. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Bonneville Ratemaking and Rates."

It is the opinion of Bonneville's General Counsel that if any rate were to be rejected by the Court, the sole remedy accorded would be a remand to Bonneville to establish a new rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville is unable to predict, however, what new rate it would establish if a rate were rejected. If Bonneville were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid. However, Bonneville is required by law to set rates to meet all of its costs. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Miscellaneous Litigation

From time to time, Bonneville may be involved in numerous other cases and arbitration proceedings, including land, contract, employment, billing disputes, federal procurement, and tort claims, some of which could result in money judgments or increased costs to Bonneville. The combined amount of damages claimed in these unrelated actions is not expected to exceed $50 million.

APPENDIX B - 1

FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS
FOR THE YEARS ENDED SEPTEMBER 30, 2023, 2022 AND 2021

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Report of Independent Auditors

To the Administrator of the
Bonneville Power Administration
United States Department of Energy

Opinion

We have audited the accompanying combined financial statements of the Federal Columbia River Power System (the "Company"), which comprise the combined balance sheets as of September 30, 2023 and 2022, and the related combined statements of revenues and expenses and of cash flows for the years then ended, including the related notes (collectively referred to as the "combined financial statements").

In our opinion, the accompanying combined financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2023 and 2022, 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.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Combined Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Combined Financial Statements

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

In preparing the combined financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the combined financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Combined Financial Statements

Our objectives are to obtain reasonable assurance about whether the combined financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will

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always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the combined financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the combined financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the combined financial statements.
- Obtain an understanding of internal control relevant to the audit 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 Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the combined financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

November 1, 2023

PricewaterhouseCoopers LLP, 805 SW Broadway, Suite 800, Portland, OR 97205
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Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Millions of Dollars)

	2023	2022
Assets		
Utility plant and nonfederal generation		
Completed plant	$ 21,674.7	$ 21,300.0
Accumulated depreciation	(8,316.0)	(7,994.8)
Net completed plant	13,358.7	13,305.2
Construction work in progress	1,733.1	1,316.7
Net utility plant	15,091.8	14,621.9
Nonfederal generation	3,380.0	3,404.6
Net utility plant and nonfederal generation	18,471.8	18,026.5
Current assets		
Cash and cash equivalents	2,037.9	1,663.0
Short-term investments in U.S. Treasury securities	-	500.8
Accounts receivable, net of allowance	84.7	41.7
Accrued unbilled revenues	282.7	458.2
Materials and supplies, at average cost	121.0	109.4
Prepaid expenses	67.9	49.0
Total current assets	2,594.2	2,822.1
Other assets		
Regulatory assets	4,272.4	4,452.2
Nonfederal nuclear decommissioning trusts	479.5	414.6
Deferred charges and other	222.0	237.2
Total other assets	4,973.9	5,104.0
Total assets	$ 26,039.9	$ 25,952.6

The accompanying notes are an integral part of these financial statements.

Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Millions of Dollars)

	2023	2022
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 5,589.1**	$ 5,859.6
Debt		
Federal appropriations	**1,597.6**	1,640.9
Borrowings from U.S. Treasury	**5,584.8**	5,384.7
Nonfederal debt	**6,885.6**	6,901.4
Total capitalization and long-term liabilities	**19,657.1**	19,786.6
Commitments and contingencies (See Note 14 to 2023 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	**199.0**	294.0
Nonfederal debt	**505.5**	468.5
Accounts payable and other	**885.0**	725.4
Total current liabilities	**1,589.5**	1,487.9
Other liabilities		
Regulatory liabilities	**1,543.2**	1,565.6
IOU exchange benefits	**1,299.2**	1,514.0
Asset retirement obligations	**1,015.1**	964.3
Deferred credits and other	**935.8**	634.2
Total other liabilities	**4,793.3**	4,678.1
Total capitalization and liabilities	**$ 26,039.9**	$ 25,952.6

The accompanying notes are an integral part of these financial statements.

Federal Columbia River Power System
Combined Statements of Revenues and Expenses
For the Years Ended September 30

(Millions of Dollars)

	2023	2022	2021
Operating revenues			
Sales	**$ 3,985.6**	$ 4,604.6	$ 3,727.8
U.S. Treasury credits	**262.3**	116.9	95.2
Total operating revenues	**4,247.9**	4,721.5	3,823.0
Operating expenses			
Operations and maintenance	**2,328.0**	2,195.8	2,152.4
Purchased power	**977.0**	358.7	248.2
Depreciation, amortization and accretion	**848.9**	841.0	826.7
Total operating expenses	**4,153.9**	3,395.5	3,227.3
Net operating revenues	**94.0**	1,326.0	595.7
Interest expense and other income, net			
Interest expense	**448.4**	417.7	427.3
Allowance for funds used during construction	**(42.0)**	(24.9)	(25.9)
Interest income	**(69.4)**	(10.6)	(1.5)
Other, net	**14.0**	(20.3)	(202.0)
Total interest expense and other income, net	**351.0**	361.9	197.9
Net (expenses) revenues	**(257.0)**	964.1	397.8
Accumulated net revenues, beginning of year	**5,859.6**	4,912.6	4,537.0
Irrigation assistance	**(13.5)**	(17.1)	(22.2)
Accumulated net revenues, end of year	**$ 5,589.1**	$ 5,859.6	$ 4,912.6

The accompanying notes are an integral part of these financial statements.

Federal Columbia River Power System
Combined Statements of Cash Flows
For the Years Ended September 30
(Millions of Dollars)

	2023	2022	2021
Cash flows from operating activities			
Net (expenses) revenues	**$ (257.0)**	$ 964.1	$ 397.8
Adjustments to reconcile net revenues to cash provided by operations:			
Depreciation, amortization and accretion	**848.9**	841.0	826.7
Boardman to Hemingway non-cash net loss	**27.9**	-	-
Other	**(20.4)**	(13.4)	(8.2)
Changes in:			
Receivables and unbilled revenues	**132.5**	(180.3)	30.0
Materials and supplies	**(11.6)**	0.1	(2.4)
Prepaid expenses	**(18.9)**	(9.5)	(3.1)
Accounts payable and other	**329.1**	334.1	465.6
Regulatory assets and liabilities	**(217.2)**	(7.4)	(291.2)
IOU exchange benefits	**(214.8)**	(208.2)	(188.2)
Nonfederal nuclear decommissioning trusts	**(60.0)**	105.3	(105.5)
Other assets and liabilities	**237.4**	(49.0)	25.9
Net cash provided by operating activities	**775.9**	1,776.8	1,147.4
Cash flows from investing activities			
Investment in utility plant, including AFUDC	**(851.9)**	(693.8)	(623.8)
Proceeds from sale of utility plant	**3.2**	13.2	2.0
U.S. Treasury securities:			
Purchases	**(250.0)**	(1,250.0)	-
Maturities	**750.0**	750.0	-
Deposits to nonfederal nuclear decommissioning trusts	**(4.9)**	(4.7)	(4.3)
Lease-purchase trust funds:			
Deposits to	**-**	-	(19.6)
Receipts from	**-**	-	27.1
Net cash used for investing activities	**(353.6)**	(1,185.3)	(618.6)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	**80.5**	43.1	119.4
Repayment	**(123.8)**	(5.0)	(49.1)
Borrowings from U.S. Treasury:			
Proceeds	**722.0**	744.0	741.0
Repayment	**(616.9)**	(694.2)	(760.7)
Nonfederal debt:			
Proceeds	**-**	-	6.6
Repayment	**(160.4)**	(208.5)	(225.9)
Debt extinguishment costs	**-**	-	(1.5)
Customers:			
Net advances for construction	**84.2**	20.3	42.3
Repayment of funds used for construction	**(20.1)**	(21.0)	(17.5)
Irrigation assistance	**(13.5)**	(17.1)	(22.2)
Net cash used for financing activities	**(48.0)**	(138.4)	(167.6)
Net increase in cash, cash equivalents and restricted cash	**374.3**	453.1	361.2
Cash, cash equivalents and restricted cash at beginning of year	**1,671.8**	1,218.7	857.5
Cash, cash equivalents and restricted cash at end of year	**$ 2,046.1**	$ 1,671.8	$ 1,218.7
Less: Restricted cash at end of year, reported in Deferred charges and other	**8.2**	8.8	10.8
Cash and cash equivalents at end of year	**$ 2,037.9**	$ 1,663.0	$ 1,207.9
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 404.2**	$ 396.4	$ 384.4
Significant noncash investing and financing activities:			
Nonfederal debt increase	**$ 674.9**	$ 705.6	$ 1,577.0
Nonfederal debt decrease	**$ (489.9)**	$ (507.4)	$ (1,288.2)
Nonfederal debt cost of issuance	**$ (3.4)**	$ (3.0)	$ (6.6)
Federal appropriations decrease	**$ -**	$ -	$ (11.5)

The accompanying notes are an integral part of these financial statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination of entities

The Federal Columbia River Power System (FCRPS) financial statements combine the accounts of the Bonneville Power Administration (BPA) with the accounts of the Pacific Northwest generating facilities of the U.S. Army Corps of Engineers (USACE) and the Bureau of Reclamation (Reclamation). The FCRPS combined financial statements also include the operations and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan (USFWS LSRCP) facilities. Consolidated with BPA is a variable interest entity (VIE) of which BPA is the primary beneficiary and from which BPA leases certain transmission facilities. (See Note 8, Debt and Appropriations, and Note 9, Variable Interest Entities.)

BPA is a separate and distinct entity within the U.S. Department of Energy; the USACE is part of the U.S. Department of Defense; and Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior. Each of the combined entities is separately managed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. BPA is a self-funding federal power marketing administration that purchases, transmits and markets power for the FCRPS. While the costs of USACE, Reclamation and USFWS LSRCP projects serve multiple purposes, only the power portion of total project costs are assigned to the FCRPS through cost allocation processes. All intracompany and intercompany accounts and transactions have been eliminated from the FCRPS financial statements.

FCRPS financial statements are prepared in accordance with generally accepted accounting principles (GAAP) of the United States of America. FCRPS financial statements also reflect the Uniform System of Accounts (USoA) as prescribed for electric public utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect other specific legislation and directives issued by U.S. government agencies. All U.S. government properties and income are tax exempt.

Use of estimates

The preparation of FCRPS financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the FCRPS financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Rates and regulatory authority

BPA establishes separate power and transmission rates in accordance with several statutory directives. Rates proposed by BPA are subject to an extensive formal hearing process, after which they are submitted by BPA and reviewed by FERC. FERC's review is based on BPA statutes that include a requirement that rates must be sufficient to ensure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs. After the final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court) if challenged by parties involved in the rate proceedings. Petitions seeking such review must be filed within 90 days of the final FERC approval. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA. BPA's rates are not structured to provide a rate of return on its assets. Rates for the two year BP-22 rate period began on Oct. 1, 2021, and concluded on Sept. 30, 2023. On Oct. 1, 2023, new rates for fiscal years 2024-2025 went into effect.

In accordance with authoritative guidance for regulated operations, certain costs or credits may be included in rates for recovery or refund over a future period and are recorded as regulatory assets or liabilities. (See Note 5, Effects of Regulation.)

Utility plant

Utility plant is stated at original cost and includes federal system hydro generation assets (i.e., Pacific Northwest generating facilities of the USACE and Reclamation) as well as transmission and other assets. The costs of substantial additions, major replacements and substantial betterments are capitalized. Costs include direct labor and materials; payments to contractors; indirect charges for engineering, supervision and certain overhead items; and an allowance for funds used during construction (AFUDC). Maintenance, repairs and replacements of items determined to be less than major units of property are charged as incurred to Operations and maintenance in the Combined Statements of Revenues and Expenses. When utility plant is retired, the original cost and any net proceeds from the disposition are charged to accumulated depreciation. (See Note 3, Utility Plant and Nonfederal Generation.)

Depreciation, amortization and accretion

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated average service lives of the various classes of property. For transmission plant, depreciation of original cost and estimated net cost of removal is computed primarily on the straight-line group life method based on estimated average service lives of the various classes of property. Periodically BPA conducts a depreciation study on transmission and general plant assets. BPA updates depreciation rates based on updated asset lives and net salvage, which considers cost of removal and salvage proceeds. The estimated net cost of removal is included in depreciation expense. (See Note 3, Utility Plant and Nonfederal Generation.)

In the event removal costs associated with transmission plant are expected to exceed salvage proceeds, a reclassification of this negative salvage is made from accumulated depreciation to a regulatory liability. As actual removal costs are incurred, the associated regulatory liability is reduced. (See Note 5, Effects of Regulation.)

Amortization expense relates to nonfederal generation assets, certain regulatory assets and finance lease right-of-use assets. (For further discussion see Note 3, Utility Plant and Nonfederal Generation; Note 5, Effects of Regulation and Note 4, Leases.)

Accretion expense is recorded throughout the fiscal year in connection with a periodic increase to the Columbia Generating Station (CGS) asset retirement obligation (ARO) liability to reflect the passage of time.

Allowance for funds used during construction

AFUDC represents the estimated cost of interest on financing the construction of new assets. AFUDC is calculated based on the construction work in progress balance and on Lease-Purchase Program trust fund balances held for construction purposes. (See Note 7, Deferred Charges and Other.) AFUDC is charged to the capitalized cost of the utility plant asset and is a reduction of Interest expense and other income, net in the Combined Statements of Revenues and Expenses.

AFUDC is capitalized at one rate for construction funded substantially by BPA and at another rate for USACE and Reclamation construction funded by congressional appropriations. (See Note 3, Utility Plant and Nonfederal Generation.) The BPA rate is determined based on the weighted-average cost of borrowing for certain types of debt and deferred credits that are related to BPA construction activity. The rate for appropriated funds is provided at the beginning of each year to BPA by the U.S. Treasury.

Nonfederal generation

BPA is party to long-term contracts for BPA to acquire all of the generating capability of Energy Northwest’s CGS nuclear power plant and Lewis County PUD’s (Public Utility District’s) Cowlitz Falls Hydroelectric Project. CGS is a nonfederal nuclear power plant owned and operated by Energy Northwest, a joint operating agency of the state of Washington. The current license termination dates for CGS and the Cowlitz Falls Project are in December 2043 and May 2036, respectively. BPA has acquired the output of the Cowlitz Falls Project through June 30, 2032. These contracts require BPA to meet all of the facilities’ operating, maintenance and debt service costs. Operations and maintenance expense for these projects are recognized based upon annual total project cash funding requirements, which vary from year to year.

Nonfederal generation assets on the Combined Balance Sheets are amortized on a straight-line basis through their respective license termination dates, with the amortization expense included in Depreciation, amortization and accretion in the Combined Statements of Revenues and Expenses. As of Sept. 30, 2023, and 2022, the CGS Nonfederal generation asset also includes approximately $98 million of prepaid nuclear fuel purchased by Energy Northwest that management anticipates CGS will begin using in 2030. Future amortization expense is expected to occur over the years in which the fuel will be used.

Cash and cash equivalents

Cash amounts for the FCRPS include cash and cash equivalents in the Bonneville Power Administration Fund (Bonneville Fund) within the U.S. Treasury and cash from certain unexpended appropriations of the USACE and Reclamation related to the FCRPS. As of Sept. 30, 2023, and 2022, cash amounts also include cash held in a margin account with BPA's financial futures broker, which BPA could access within one day. Cash equivalents in the Bonneville Fund consist of investments in non-marketable market-based special securities issued by the U.S. Treasury with original maturities of 90 days or less at the date of investment. The carrying value of cash and cash equivalents approximates fair value.

Investments in U.S. Treasury securities

BPA participates in the U.S. Treasury's Federal Investment Program, which provides investment services to federal government entities that have funds on deposit with the U.S. Treasury and statutory authority to invest those funds. Investments of the funds are generally restricted to U.S. Treasury market-based special securities and are informed by prevailing rates of interest for various short-term or longer-term investments.

Investments in U.S. Treasury securities are carried at amortized cost, which approximates fair value, and reflect the ability and intent to hold the securities to maturity. The fair value measurements of investments in U.S. Treasury securities are considered Level 2 in the fair value hierarchy as defined by the accounting guidance for fair value measurements and disclosures. (See Note 13, Fair Value Measurements.)

Concentrations of credit risks

General credit risk

Financial instruments that potentially subject the FCRPS to concentrations of credit risk consist primarily of BPA accounts receivable. Credit risk relates to the loss that might occur as a result of counterparty non-performance.

BPA's accounts receivable are spread across a diverse group of customers throughout the western United States and Canada, and include consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators and others. BPA's accounts receivable exposure is generally from large and stable counterparties and does not represent a significant concentration of credit risk. During fiscal years 2023, 2022 and 2021, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings.

BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure. To further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, and cash in the form of prepayments, deposits or escrow funds, from some counterparties. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. (See Note 12, Risk Management and Derivative Instruments.)

Allowance for doubtful accounts

Management reviews accounts receivable to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific customer accounts, based upon the best available facts and circumstances of customers that may be unable to meet their financial obligations, and a reserve for all other customers based on historical experience. The allowance is not material to the financial statements.

Derivative instruments

Derivative instruments consist primarily of forward electricity contracts and are measured at fair value and recognized on the Combined Balance Sheets as either Deferred charges and other or as Deferred credits and other. Changes in fair value are deferred as either Regulatory assets or Regulatory liabilities on the Combined Balance Sheets in accordance with regulated operations accounting guidance. Recognition of these contracts in the Combined Statements of Revenues and Expenses occurs in Sales or Purchased power when the contracts settle. BPA elects the normal purchases and normal sales exception under derivatives and hedging accounting guidance for certain contracts that require physical delivery, are expected to be used or sold in the normal course of business and meet the derivative accounting definition of a capacity contract. The FCRPS does not apply hedge accounting. (See Note 12, Risk Management and Derivative Instruments.)

Fair value

Carrying amounts of current assets and current liabilities approximate fair value based on the short-term nature of these instruments. Fair value measurements are applied to certain financial assets and liabilities and to determine fair value disclosures in accordance with GAAP. When developing fair value measurements, it is BPA's policy to use quoted market prices whenever available or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, current market and contractual prices for underlying instruments, market interest rates and yield curves, and credit spreads, as well as other relevant economic measures. (See Note 12, Risk Management and Derivative Instruments and Note 13, Fair Value Measurements.)

Operating revenues and net revenues

Sales include estimated unbilled revenues. (See Note 2, Revenue Recognition.) Net revenues over time are committed to payment of operational obligations, including debt for both operating and non-operating nonfederal projects, debt service on bonds BPA issues to the U.S. Treasury, the repayment of federal appropriations for the FCRPS, and the payment of certain irrigation costs.

U.S. Treasury credits

U.S. Treasury credits represent nonpower-related costs that BPA recovers from the U.S. Treasury in accordance with certain laws. (See Note 2, Revenue Recognition.)

Purchased power

Purchased power expense represents wholesale power purchases that are meant to augment the FCRPS resource pool to meet loads and obligations. In addition, this expense includes the costs of certain water storage agreements between BPA and third parties. Purchased power excludes operations and maintenance expenses associated with CGS and the Cowlitz Falls Hydroelectric Project, and with certain contracts for renewable resources that BPA management considers part of the FCRPS resource pool.

Interest expense

Interest expense includes interest associated with nonfederal debt related to operating or terminated nonfederal generation assets, bonds issued by BPA to the U.S. Treasury, the unpaid balance of federal appropriations scheduled for repayment, and other nonfederal debt and certain liabilities. In addition, interest expense includes the amortization of bond premiums, discounts and costs of issuance. Reductions to interest expense include the amortization of a capitalization adjustment regulatory liability. (See Note 5, Effects of Regulation.)

Interest income

Interest income includes interest earnings on market-based special securities in the Bonneville Fund and interest earnings from other sources.

Other, net

Other, net primarily includes dividend income and realized gains and losses associated with the nonfederal nuclear decommissioning trusts for CGS. In addition, gains and losses incurred because of early debt extinguishment are recorded to this caption. In fiscal year 2023, Other, net also includes $31 million net non-cash expense related to the “Boardman to Hemingway (B2H) with Transfer Service” transaction in March 2023. For further information on the B2H transaction, see Note 7, Deferred Charges and Other. In fiscal year 2021, Other, net also included $20 million related to the amortization of Energy Northwest Projects 1 and 4 site restoration regulatory liability. This treatment was consistent with the BP-20 rate case.

Residential Exchange Program

In order to provide residential and small farm customers of qualifying regional utilities, primarily IOUs, access to power benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Whenever a Pacific Northwest electric utility offers to sell power to BPA at the utility’s average system cost of resources, BPA purchases such power and offers, in exchange, to sell an equivalent amount of power at BPA’s priority firm exchange rate to the utility for resale to that utility’s residential and small farm consumers. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing BPA’s power rates. REP costs are recognized when incurred and are included in Operations and maintenance in the Combined Statements of Revenues and Expenses.

In fiscal year 2011, BPA signed the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement), resolving disputes related to the REP. The 2012 REP Settlement Agreement provided for fixed “Scheduled Amounts” payable to the IOUs through fiscal year 2028. (See Note 10, Residential Exchange Program.)

Pension and other postretirement benefits

Federal employees associated with the operation of the FCRPS participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate after retirement in the Federal Employees Health and Benefit Program and the Federal Employees Group Life Insurance Program. All such postretirement systems and programs are sponsored by the U.S. Office of Personnel Management; therefore, the FCRPS financial statements do not include accumulated plan assets or liabilities related to the administration of such programs. As part of BPA’s scheduled payment each year to the U.S. Treasury for bonds and other purposes, BPA makes contributions to cover the estimated annual unfunded portion of FCRPS pension and postretirement benefits. These contribution amounts are paid to the U.S. Treasury and are recorded as Operations and maintenance in the Combined Statements of Revenues and Expenses during the year to which the payment relates.

SUBSEQUENT EVENTS

Management has performed an evaluation of events and transactions for potential FCRPS recognition or disclosure through Nov. 1, 2023, which is the date the financial statements were issued.

2. Revenue Recognition

DISAGGREGATED REVENUE

Years ended Sept. 30 - millions of dollars	2023	2022	2021
Sales			
Power			
Firm	$ 1,817.0	$ 2,095.0	$ 2,122.7
Surplus[1]	962.4	1,337.0	561.2
Transmission	1,097.2	1,070.4	966.1
Other[2]	109.0	102.2	77.8
Sales	$ 3,985.6	$ 4,604.6	$ 3,727.8
U.S. Treasury credits[3]	262.3	116.9	95.2
Total operating revenues[4]	$ 4,247.9	$ 4,721.5	$ 3,823.0

1 Surplus revenue includes $227.9 million, $575.2 million, and $226.4 million of derivative commodity contracts and related operational hedging activity for fiscal years 2023, 2022 and 2021, respectively, which are not considered revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
2 Other revenue includes $42.6 million, $41.7 million and $22.7 million for fiscal years 2023, 2022 and 2021, respectively, that are not classified as revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
3 U.S. Treasury credits are not classified as revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
4 Revenue from contracts with customers was $3,715.1 million, $3,987.7 million and $3,478.7 million for fiscal years 2023, 2022 and 2021, respectively.

SALES

A substantial majority of FCRPS revenues is from rate-regulated sales of power and transmission products and services. All revenues are from contracts with customers except for U.S. Treasury credits, derivatives and certain other revenues as shown in the table above. BPA establishes rates for its power and transmission services in a formal rate proceeding. The power and transmission rate schedules and general rate schedule provisions establish the rates, billing determinants, and rate provisions applicable to all BPA power and transmission contracts. Charges for services specified in the rate schedules and their provisions represent the amount billed by BPA for the goods or services used and purchased by its customers.

BPA has elected to apply the right-to-invoice practical expedient to FCRPS rate-regulated revenues from power and transmission services. Amounts invoiced correspond directly with the value to the customers for energy or services provided by the FCRPS reporting entities. Therefore, revenue from power and transmission sales, which includes billed and estimated unbilled amounts, is recognized over time upon the delivery of energy or services to the customers. The customers receive and benefit from the value of power and transmission at the time of delivery. Payments for amounts billed by BPA are generally due from customers within 20 days of billing. There are no material significant financing components.

“Firm” power consists of energy, capacity, or both, that is guaranteed to be available to the customer at all times during the period covered by a contract, except by reason of certain uncontrollable forces or service interruption provisions. The Northwest Power Act obligates BPA to meet a utility customer’s firm consumer load net of the customer’s resources used to serve its load. In addition, BPA sells firm power to other federal agencies and to a limited number of direct service industries within the region for their direct consumption. The vast majority of firm power sold by BPA in fiscal years 2023, 2022 and 2021 was to preference customers, which make long-term power purchases from BPA at cost-based rates to meet their retail loads in the region. Preference customers are qualifying public utility districts, municipalities, consumer-owned electric cooperatives, and tribal utilities within the region. BPA’s current power sales agreements with preference customers are in effect through fiscal year 2028.

"Surplus" power consists of energy and capacity that can be provided on an hourly or other short-term basis that is surplus to meeting certain firm loads as defined in the Northwest Power Act. BPA often describes the sale of surplus power as secondary sales. Most surplus power is sold to Pacific Northwest and California markets under short-term power sales that allow for flexible negotiated prices, or under longer-term contracts. The availability of surplus power depends primarily on precipitation and reservoir storage levels, performance of the Columbia Generating Station, BPA's firm power load obligations and other factors. Secondary revenues from the sale of surplus power are highly variable and depend on market conditions and the resulting prices. Amounts disclosed are net of bookouts, which occur when sales and purchases are scheduled with the same counterparty on the same path for the same hour.

Also included within Surplus sales are revenues from derivative commodity contracts in scope of ASC 815, Derivatives and Hedging, which are not considered revenue from contracts with customers under ASC 606. Derivative revenues are reported net of bookouts and primarily source from certain secondary power contracts that involve derivative instruments. (For further information on derivatives, see Note 1, Summary of Significant Accounting Policies, and Note 12, Risk Management and Derivative Instruments.)

"Transmission" revenues consist primarily of revenue for the transmission of power on BPA's network within and through the BPA service area. Point-to-point long-term contracts exceeding one year comprise the majority of network revenues and allow customers to move energy on a firm basis from a point of receipt to a point of delivery. In addition, Network Integration Transmission Service delivers power to load within BPA's balancing authority area and is a significant component of transmission revenues. Revenue from ancillary services and the Southern Intertie also comprise a significant portion of transmission revenues. Ancillary services ensure transmission grid reliability and include items such as scheduling, dispatch, balancing reserves and other services. The Southern Intertie is a system of transmission lines used primarily to transmit power between the Pacific Northwest and California. Nearly all intertie revenue is from long-term contracts exceeding one year in duration. Transmission customers include entities that buy and sell non-federal power in the region, in-region purchasers of federal power, generators, power marketers and utilities that seek to transmit power into, out of or through the region.

"Other" revenues source primarily from the sales of power and other services or items by Reclamation and USACE. In particular, Reclamation sells power to certain Pacific Northwest irrigation districts. Other revenues also include reimbursable revenues associated with work performed for BPA customers. Reimbursable revenues are offset by an equivalent amount of reimbursable expenses.

Also included within other revenues are the following types of revenue not with customers: leasing fees that BPA receives as the lessor of certain fiber optic cables and other assets; revenue from deferred project revenue funded in advance, which is recognized over the life of the corresponding transmission assets once placed in service; and realized gains on financial futures contracts. (See Note 11, Deferred Credits and Other for further information on deferred project revenue funded in advance.)

U.S. TREASURY CREDITS

U.S. Treasury credits represent BPA's recovery of certain nonpower-related costs from the U.S. Treasury in accordance with certain laws. The primary U.S. Treasury credit is the 4(h)(10)(C) credit provided for in the Northwest Power Act. This Act requires BPA to recover the nonpower portion of expenditures—set at 22.3%—that BPA makes for fish and wildlife protection, mitigation and enhancement. Through Section 4(h)(10)(C), the Northwest Power Act ensures that the costs of mitigating these impacts are allocated between the power-related and other purposes of the federal hydroelectric projects of the FCRPS. Power-related costs are recovered in BPA's rates. U.S. Treasury credits are reported as a component of Operating revenues in the Combined Statements of Revenues and Expenses.

As part of its annual payment to the U.S. Treasury, BPA applies the U.S. Treasury credits earned each fiscal year against various categories of payment obligations. For example, BPA may apply U.S. Treasury credits against interest expense or liabilities such as borrowings from U.S. Treasury and federal appropriations.

CONTRACT BALANCES

As of Sept. 30 — millions of dollars	2023	2022
Receivable assets		
Accounts receivable, net of allowance	$ 84.7	$ 41.7
Accrued unbilled revenues	282.7	458.2
Contract liabilities		
Customer prepaid power purchases	$ 139.2	$ 163.0
Third AC Intertie capacity agreements	82.6	86.1
Unearned revenue from customer deposits	66.0	37.8
Revenue recognized during the fiscal year from amounts included in contract liabilities at the beginning of the year	$ 94.6	$ 105.4

Accounts receivable and accrued unbilled revenues source primarily from contracts with customers.

Contract liabilities represent an entity's unsatisfied performance obligation to transfer goods or services to a customer from which the entity has received consideration. The contract liability amounts in the table above show expected future revenues to be recorded as power is delivered (for customer prepaid power purchases), over the estimated life of transmission assets placed in service (for Third AC Intertie capacity agreements), or as expenditures are incurred (for unearned revenue from customer deposits). These contract liabilities have no variable consideration and require little or no significant judgment in revenue recognition. The average contract term varies by customer and type and may span several years. (See Note 8, Debt and Appropriations, for further information on customer prepaid power purchases, and Note 11, Deferred Credits and Other, for further information on Third AC Intertie capacity agreements and unearned revenue from customer deposits.)

3. Utility Plant and Nonfederal Generation

As of Sept. 30 — millions of dollars		2023		2022	2023 Estimated average service lives
Completed plant					
Federal system hydro generation assets	$	10,337.3	$	10,171.3	75 years
Transmission assets		11,230.0		11,023.7	51 years
Other assets		107.4		105.0	8 years
Completed plant	$	21,674.7	$	21,300.0	
Accumulated depreciation					
Federal system hydro generation assets	$	(4,139.2)	$	(4,002.2)	
Transmission assets		(4,126.6)		(3,939.0)	
Other assets		(50.2)		(53.6)	
Accumulated depreciation	$	(8,316.0)	$	(7,994.8)	
Construction work in progress					
Federal system hydro generation assets	$	588.5	$	532.7	
Transmission assets		1,118.7		754.5	
Other assets		25.9		29.5	
Construction work in progress	$	1,733.1	$	1,316.7	
Nonfederal generation	$	3,380.0	$	3,404.6	
Net utility plant and nonfederal generation	$	18,471.8	$	18,026.5	

Allowance for funds used during construction

Fiscal year	2023	2022	2021
BPA rate	3.0%	2.4%	2.6%
Appropriated rate	3.6%	0.1%	0.1%

Amounts accrued in Accounts payable and other on the Combined Balance Sheets for Construction work in progress assets were approximately $122 million, $93 million, and $92 million as of Sept. 30, 2023, 2022, and 2021, respectively.

4. Leases

An arrangement contains a lease if a lessee has the right to control an identified asset for a period of time in exchange for consideration. At contract inception, management determines whether an arrangement contains a lease and lease classification, if applicable. At the lease commencement date, lease right-of-use (ROU) assets and lease liabilities are recorded based upon the present value of lease payments over the lease term, including initial direct costs, if any. If a contract provides an implicit rate, it is used to determine the present value of future lease payments. If a contract does not provide an implicit rate, management uses the incremental borrowing rate available at lease commencement. Operating lease ROU assets include any lease payments made at or before the commencement date and exclude lease incentives.

Certain lease arrangements contain renewal or early termination options. If management is reasonably certain to exercise these options, they are included in the calculation of the ROU asset and lease liability by incorporating the option into the lease term. Certain renewal options include an adjustment to future lease cost based upon various factors, such as pre-determined percentage increases, the Consumer Price Index, or other methods. Management has also elected to account for arrangements with lease and non-lease components as a single lease component.

Operating leases are primarily for office spaces and leased vehicles. Operating lease terms range from one to 36 years. Finance leases are primarily for transmission lines and equipment. Finance lease terms range from one to 64 years. There were no material lessor arrangements as of Sept. 30, 2023, and 2022.

The following table provides supplemental balance sheet information related to leases:

As of Sept. 30 — millions of dollars	Financial Statement Line Item	2023	2022
Operating leases			
ROU assets	Deferred charges and other	$ 91.4	$ 98.3
Short-term lease liability	Accounts payable and other	16.4	31.6
Long-term lease liability	Deferred credits and other	75.0	66.7
Finance leases			
ROU assets	Completed plant	$ 99.1	$ 95.8
Short-term lease liability	Nonfederal debt	4.9	7.3
Long-term lease liability	Nonfederal debt	99.5	93.8

The following table provides supplemental expense information related to total lease costs:

Years ended Sept. 30 — millions of dollars	Financial Statement Line Item	2023	2022	2021
Operating lease cost[1]	Operations and maintenance	$ 18.7	$ 18.6	$ 19.0
Finance lease cost:				
Amortization of ROU assets	Depreciation, amortization and accretion	5.2	4.5	3.7
Interest on lease liabilities	Interest expense	5.1	5.1	5.0
Total lease costs		$ 29.0	$ 28.2	$ 27.7

[1]Includes variable lease costs, which were immaterial for the fiscal years ended Sept. 30, 2023, 2022 and 2021.

	Weighted-average remaining lease term	Weighted-average discount rate
Operating leases	6.7 years	2.6%
Finance leases	47.1 years	4.9%

The following table provides supplemental cash flow information related to leases:

Years ended Sept. 30 - millions of dollars	2023	2022	2021
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash outflows:			
Operating lease payments	$ 18.7	$ 18.6	$ 19.0
Interest on finance leases	5.1	5.1	5.0
Financing cash outflows:			
Principal payments on finance lease	4.4	3.8	2.9
Right-of-use assets obtained in exchange for new lease obligations			
Operating leases	9.3	3.0	13.4
Finance leases	8.2	7.0	11.9

The following table provides maturities of operating lease liabilities:

As of Sept. 30 - millions of dollars	2023
2024	$ 18.6
2025	16.0
2026	15.3
2027	11.8
2028	11.4
2029 and thereafter	27.0
Total undiscounted lease liabilities	$ 100.1
Less: Amounts representing interest	8.7
Total lease liabilities	$ 91.4

See Note 8, Debt and Appropriations, for finance lease maturity analysis.

5. Effects of Regulation

Regulatory assets include the following items:

REGULATORY ASSETS

As of Sept. 30 — millions of dollars	2023	2022
Terminated nuclear facilities	$ 1,425.4	$ 1,495.8
IOU exchange benefits	1,299.2	1,514.0
Columbia River Fish Mitigation	745.2	766.1
Phase 2 Implementation Plan (P2IP) Settlement Agreement	252.8	—
Fish and wildlife measures	213.5	233.9
Trojan decommissioning and site restoration	92.9	77.3
Decommissioning and site restoration	75.7	124.8
Conservation measures	48.3	81.3
Spacer damper replacement program	46.0	46.8
Terminated I-5 Corridor Reinforcement Project	26.0	52.0
Legal claims and settlements	22.0	22.0
Federal Employees' Compensation Act	17.8	18.9
Other	3.6	4.1
Terminated hydro facilities	2.2	4.2
Derivative instruments	1.8	11.0
Total	$ 4,272.4	$ 4,452.2

"**Terminated nuclear facilities**" consist of amounts to be recovered in future rates to satisfy the nonfederal debt for Energy Northwest Projects 1 and 3. These assets are amortized to depreciation, amortization and accretion through 2043, as established in the rate case.

"**IOU exchange benefits**" reflect amounts to be recovered in rates through 2028 for the IOU exchange benefits liability incurred as part of the 2012 REP Settlement Agreement. These amounts are amortized to operations and maintenance expense. (See Note 10, Residential Exchange Program.)

"**Columbia River Fish Mitigation**" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. Through fiscal year 2021, these costs were recovered in rates over 75 years and amortized to depreciation, amortization and accretion expense. Beginning in fiscal year 2022, these costs are no longer deferred and are instead recorded as operations and maintenance expense when incurred. In addition, beginning in fiscal year 2022 the amortization period for remaining deferred amounts has changed from 75 years to 50 years as stated in the BP-22 rate case.

"**Phase 2 Implementation Plan (P2IP) Settlement Agreement**" represents the deferral of expenses related to the P2IP settlement agreement signed in September 2023. BPA expects that these costs will be recovered through future rates and will be amortized to depreciation, amortization and accretion expense beginning in fiscal year 2026. The amortization period will be determined prior to the BP-26 rate proposal. (For further information on the P2IP transaction, see Note 11, Deferred Credits and Other.)

"**Fish and wildlife measures**" consist of deferred fish and wildlife project expenses to be recovered in future rates. These costs are amortized to depreciation, amortization and accretion expense over a period of 15 years.

"**Trojan decommissioning and site restoration**" reflects the amount to be recovered in future rates for funding the asset retirement obligation (ARO) liability related to the former Trojan nuclear facility. This amount equals the associated liability. (See Note 6, Asset Retirement Obligations.)

"**Decommissioning and site restoration**" represents unrealized losses in the nonfederal nuclear decommissioning trust assets for the Columbia Generating Station. (See Note 6, Asset Retirement Obligations.)

"**Conservation measures**" consist of the costs of deferred energy conservation measures to be recovered in future rates. These costs are amortized to depreciation, amortization and accretion expense over periods of 12 or

20 years. BPA deferred certain costs of energy conservation measures through fiscal year 2015 and, beginning with fiscal year 2016, began recording such costs as operations and maintenance expense when incurred.

"**Spacer damper replacement program**" consists of costs to replace deteriorated spacer dampers on certain transmission lines and are recovered in future rates under the Spacer Damper Replacement Program. These costs are amortized to depreciation, amortization and accretion expense over a period of 25 or 30 years.

"Terminated I-5 Corridor Reinforcement Project" consists of the costs to be recovered in future rates for preliminary construction and related activities for the former I-5 Corridor Reinforcement Project. These costs are amortized to depreciation, amortization and accretion expense through 2024, as established in the rate case.

"**Legal claims and settlements**" reflect amounts to be recovered in future rates to satisfy accrued liabilities related to legal claims and settlements. These costs will be recovered and amortized to operations and maintenance expense over a period to be established during future rate cases.

"**Federal Employees' Compensation Act**" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits. This amount equals the associated liability, and related expenses are recorded to operations and maintenance expense as payments are made. (See Note 11, Deferred Credits and Other.)

"**Terminated hydro facilities"** consist of the amounts to be recovered in future rates to satisfy nonfederal debt for the Northern Wasco Hydro Project, for which BPA ceased its participation as recipient of the project's electric power. These assets are amortized to depreciation, amortization and accretion through 2025, as established in the rate case. (See Note 8, Debt and Appropriations.)

"**Derivative instruments**" reflect the unrealized losses from BPA's derivative portfolio. These amounts are deferred over the corresponding underlying contract delivery months. (See Note 12, Risk Management and Derivative Instruments.)

Regulatory liabilities include the following items:

REGULATORY LIABILITIES

As of Sept. 30 — millions of dollars	2023	2022
Capitalization adjustment	$ 822.9	$ 887.8
Accumulated plant removal costs	666.2	621.0
Derivative instruments	51.5	55.4
Other	2.6	1.4
Total	$ 1,543.2	$ 1,565.6

"**Capitalization adjustment**" is the difference between the outstanding balance of federal appropriations, plus $100 million, before and after refinancing under the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, 16 U.S.C. 838(l). Consistent with treatment in BPA's power and transmission rate cases, this adjustment is amortized over a 40-year period through fiscal year 2036. Amortization of the capitalization adjustment as a reduction to interest expense was $64.9 million each year for fiscal years 2023, 2022 and 2021.

"**Accumulated plant removal costs**" represent a liability for amounts previously collected through rates as part of depreciation expense. The liability increases as depreciation expense is incurred and is reduced as actual costs of removal, net of proceeds, are incurred. (See Note 1, Summary of Significant Accounting Policies.)

"**Derivative instruments**" reflect the unrealized gains from BPA's derivative portfolio. These amounts are deferred over the corresponding underlying contract delivery months. (See Note 12, Risk Management and Derivative Instruments.)

6. Asset Retirement Obligations

Asset retirement obligations include the following items:

As of Sept. 30 — millions of dollars	2023	2022
CGS decommissioning and site restoration	$ 921.8	$ 884.3
Trojan decommissioning	92.9	77.3
Energy Northwest Projects 1 and 4 site restoration	0.4	2.7
Total	$ 1,015.1	$ 964.3

AROs represent the legal obligations associated with the future retirement of certain tangible, long-lived assets. FCRPS AROs are recognized based on the estimated fair value of the dismantlement and restoration costs, primarily associated with the retirement of the Columbia Generating Station. BPA also has AROs for a 30% share of the former Trojan nuclear power plant decommissioning activities and for certain Energy Northwest-related site restoration activities. ARO liabilities are adjusted for any revisions, expenditures and the passage of time.

As of Sept. 30 — millions of dollars	2023	2022	2021
Beginning Balance	$ 964.3	$ 929.2	$ 890.7
Activities:			
Accretion	40.2	38.6	37.1
Expenditures	(5.5)	(6.1)	(8.2)
Revisions	16.1	2.6	9.6
Ending Balance	$ 1,015.1	$ 964.3	$ 929.2

Based on agreements in place, BPA directly funds Eugene Water and Electric Board's 30% share of the former Trojan nuclear power plant decommissioning activities that consist of long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI). BPA funds these costs through current rates, with the expenses included in Operations and maintenance in the Combined Statements of Revenues and Expenses. Trojan decommissioning primarily relates to the storage of spent nuclear fuel through 2059 at the former nuclear plant site. Decommissioning of the ISFSI and final site restoration activities is not expected to occur before 2059, which is the year the Nuclear Regulatory Commission (NRC) extended the fuel storage license through. In fiscal year 2023, BPA management revised the estimate for the ARO liability by $14.9 million. This change in estimate was driven by increases in expected annual ISFSI operation costs primarily due to additional personnel and construction-related expenses. A $14.9 million increase to Regulatory assets on the Combined Balance Sheets offset the increased ARO liability in fiscal year 2023.

Based on a prior settlement agreement with the DOE, BPA receives an annual reimbursement for certain costs related to monitoring the spent nuclear fuel. BPA reduces operations and maintenance expense when it receives the reimbursement, which was $1.8 million, $1.5 million, and $1.6 million in fiscal years 2023, 2022, and 2021, respectively.

The FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO because no legal obligation exists to remove these assets.

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — millions of dollars	2023		2022	
	Amortized cost	Fair value	Amortized cost	Fair value
Equity securities	$ 442.4	$ 396.1	$ 439.4	$ 337.8
Debt securities	95.9	66.4	82.5	59.3
Cash and cash equivalents	17.0	17.0	17.5	17.5
Total	$ 555.3	$ 479.5	$ 539.4	$ 414.6

These assets are trust fund account balances, primarily for CGS decommissioning and site restoration costs, but also for site restoration at Energy Northwest Projects 1 and 4, which terminated prior to completion. The fair value of the trust fund balances for CGS decommissioning and site restoration costs as of Sept. 30, 2023, and 2022 were $462.5 million and $397.1 million, respectively. The investment securities in the CGS decommissioning and site restoration trust fund accounts comprise both equity and debt securities and are recorded at fair value in accordance with applicable accounting guidance. Equity securities include both domestic and international index mutual funds. Debt securities are classified as available-for-sale and include bond mutual funds that hold inflation-protected securities. The trust fund balances for the site restoration at Energy Northwest Projects 1 and 4 were $17 million and $17.5 million, respectively. The site restoration fund for Energy Northwest Projects 1 and 4 is invested in a money market fund that is considered cash and cash equivalents.

External trust fund accounts for decommissioning and site restoration costs for CGS are funded monthly, with these contributions recorded as an increase to the trust fund asset. The CGS decommissioning trust fund account was established to provide for decommissioning at the end of the project’s operations in accordance with NRC requirements. The NRC requires that this period be no longer than 60 years from the time the plant ceases operations. Decommissioning funding requirements for CGS are based on a 2019 site-specific decommissioning study for CGS and the current license termination date, which is in December 2043. The CGS trust fund accounts are funded and managed by BPA in accordance with NRC requirements and site certification agreements.

Unrealized gains and losses are recorded to a regulatory liability or regulatory asset, respectively. Realized gains and losses for CGS are recorded to Other, net in the Combined Statements of Revenues and Expenses and were considered when establishing rates for fiscal years 2021 through 2023. Realized gains reported for fiscal years 2023, 2022 and 2021 were $0.1 million, $2.9 million, and $164.1 million, respectively.

Contribution payments to the CGS trust fund accounts for fiscal years 2023, 2022 and 2021 were $4.9 million, $4.7 million and $4.3 million, respectively. Based on current estimates, BPA and Energy Northwest have no obligation to make further payments into the site restoration fund for Energy Northwest Projects 1 and 4.

7. Deferred Charges and Other

Deferred Charges and Other include the following items:

As of Sept. 30 — millions of dollars	2023	2022
Operating leases	$ 91.4	$ 98.3
Derivative instruments	51.5	55.4
Lease-Purchase trust funds	35.7	34.0
Water storage agreements	14.7	—
Transmission line-related receivables	10.4	—
Spectrum Relocation Fund	8.2	8.8
Cloud computing arrangements	6.2	7.8
Other	3.9	4.6
Funding agreements	—	28.3
Total	$ 222.0	$ 237.2

"**Operating leases**" represent right-of-use assets that are amortized to operations and maintenance expense over the term of the related leases. (See Note 4, Leases.)

"**Derivative instruments**" represent unrealized gains from BPA's derivative portfolio, which primarily includes physical power purchase and sale transactions.

"**Lease-Purchase trust funds**" are investments held in separate trust accounts outside the Bonneville Fund for the construction of leased transmission assets, the use of which BPA has acquired under lease-purchase agreements. The amounts held in trust are also used in part for debt service payments during the construction period and include an investment fund mainly for future principal and interest debt service payments. (See Note 8, Debt and Appropriations.) Interest income and realized and unrealized gains or losses on amounts held in trust for construction are recorded as AFUDC. Interest income and gains and losses on other trust balances are recorded as either income or expense in the period when earned. At the time of debt extinguishment, unspent trust funds under a particular transaction are used to repay the related lease-purchase debt and associated debt extinguishment costs for that transaction.

The Lease-Purchase trust funds are primarily comprised of held-to-maturity fixed-income investments and cash and cash equivalents.

Investments classified as held-to-maturity were $19.1 million and $19.2 million as of Sept. 30, 2023 and 2022, and are recorded at amortized cost. The fair value of held-to-maturity investments exceeded amortized cost by approximately $1 million and $2 million as of Sept. 30, 2023, and 2022, respectively. Unrealized gains comprise the difference between amortized cost and fair value for both years. Held-to-maturity investments as of Sept. 30, 2023, mature in November 2030.

As of Sept. 30, 2023, and 2022, trust balances also included cash and cash equivalents of $14 million and $14.7 million, respectively.

Investments classified as available-for-sale were $2.6 million and $0.1 million at Sept. 30, 2023, and 2022, respectively. These investments are held for construction purposes and are stated at fair value based on quoted market prices. The fair value of these investments approximates amortized cost, with immaterial unrealized and realized gains or losses recorded during fiscal years 2023, 2022, and 2021. Available-for-sale investments as of Sept. 30, 2023, mature in October and November 2023. (See Note 13, Fair Value Measurements.)

"**Water storage agreements**" represent amounts owed to BPA by BC Hydro, an electric utility owned by the Province of British Columbia. Yearly fluctuations in water levels, river operations and storage plans, particularly at certain dams in and near Canada, affect the amounts owed to or from BC Hydro. The final annual amount is invoiced based on August 31 ending balances.

"**Transmission line-related receivables**" represent the receivable assets recorded in relation to the March 2023 Boardman to Hemingway with Transfer Service transaction, in which BPA transferred its 24.24% permitting interest share in the proposed Boardman to Hemingway transmission line to Idaho Power Company (IPC). Taking into account the time value of money and project risks, the permitting interest transfer resulted in a $3.4 million financial asset and a corresponding non-cash gain recorded to Other, net related to the sale.

Additionally, BPA paid IPC a $10 million security payment which, once adjusted for the time value of money, resulted in a $7 million deferred asset increase, and a $3 million loss recorded to Other, net.

BPA expects to receive approximately $31 million, plus interest, from IPC over 10 years beginning 10 years after IPC builds and energizes the B2H transmission line and also reaches service thresholds as defined in the aforementioned March 2023 contracts. Additionally, upon energization BPA expects to recover the $10 million security payment from IPC.

"**Spectrum Relocation Fund**" was created to reimburse certain federal agencies such as BPA for the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to the affected federal agencies. These amounts previously received from the U.S. Treasury are held as restricted cash in the Bonneville Fund for the sole purpose of constructing replacement assets. These amounts are the only source of restricted cash reported on the Combined Statements of Cash Flows.

"**Cloud computing arrangements**" represent the capitalized implementation costs incurred in a cloud computing arrangement that is a service contract. These costs are amortized to operations and maintenance expense over the terms of the respective contracts once placed in service.

"**Funding agreements**" represent deferred costs associated with BPA's contractual obligations to determine the feasibility of certain joint transmission projects. In March 2023, BPA wrote off $31.4 million of deferred costs to Other, net, in connection with the Boardman to Hemingway with Transfer Service transaction. For more information on this transaction, see Transmission line-related receivables in this table.

8. Debt and Appropriations

As of Sept. 30 — millions of dollars		2023		2022	
	Terms	Carrying Value	Weighted-Average Interest Rate	Carrying Value	Weighted-Average Interest Rate
Nonfederal debt					
Nonfederal generation:					
Columbia Generating Station	0.9 – 6.8% through 2042	$ 3,381.9	4.5%	$ 3,295.9	4.5%
Cowlitz Falls Hydro Project	4.0 – 5.3% through 2032	52.0	5.5	56.4	5.5
Terminated nonfederal generation:					
Nuclear Project 1	0.9 – 5.0% through 2042	837.5	4.8	824.1	4.7
Nuclear Project 3	2.9 – 5.0% through 2042	970.6	4.9	950.3	4.9
Northern Wasco Hydro Project	5.0% through 2024	3.6	5.0	5.3	5.0
Lease-Purchase Program:					
Lease-purchase liability	2.2 – 3.7% through 2046	1,766.8	2.8	1,838.3	2.8
NIFC debt	5.4% through 2034	119.1	5.4	119.0	5.4
Finance lease liability	0.6 – 6.9% through 2087	104.4	4.9	101.1	5.0
Other financial liability	3.4% through 2043	16.0	3.4	16.5	3.4
Customer prepaid power purchases	4.3 – 4.6% through 2028	139.2	4.5	163.0	4.5
Total Nonfederal debt		$ 7,391.1	4.2%	$ 7,369.9	4.2%
Federal debt and appropriations					
Borrowings from U.S. Treasury	0.4 – 5.9% through 2053	$ 5,783.8	3.4%	$ 5,678.7	3.0%
Federal appropriations	1.4 – 4.4% through 2073	1,123.9	3.2	1,242.9	3.3
Federal appropriations (not scheduled for repayment)		473.7	n/a	398.0	n/a
Total Federal debt and appropriations		$ 7,381.4	3.4%	$ 7,319.6	3.1%
Total debt and appropriations		$ 14,772.5	3.8%	$ 14,689.5	3.6%

NONFEDERAL DEBT

Nonfederal generation and Terminated nonfederal generation

As described in Note 1, Summary of Significant Accounting Policies, Nonfederal generation section, BPA is party to long-term contracts for BPA to acquire all of the generating capability of Energy Northwest's Columbia Generating Station and, through June 2032, all of Lewis County PUD's Cowlitz Falls Hydroelectric Project. Under certain agreements, BPA also has financial responsibility for meeting all costs of Energy Northwest's Projects 1 and 3, including debt service costs of bonds and other financial instruments issued for the projects, even though these projects have been terminated. BPA is also required by a "Settlement and Termination Agreement" between BPA and Northern Wasco PUD to pay amounts equal to annual debt service on certain bonds of the Northern Wasco Hydro Project. Under the Settlement and Termination Agreement, BPA ceased its participation in this project.

Cowlitz Falls Hydroelectric Project debt of $52 million is callable, in whole or in part, at Lewis County PUD's option with the approval of BPA, at 100% of the principal amount plus accrued interest.

BPA recognizes certain expenses for these nonfederal generation and terminated nonfederal generation projects based on annual total project cash funding requirements, which include interest expense and operating and maintenance expense. BPA recognized operating and maintenance expense for these projects of $327 million, $287.4 million and $319.4 million in fiscal years 2023, 2022 and 2021, respectively, which is included in Operations and maintenance in the Combined Statements of Revenues and Expenses. On the Combined Balance Sheets, related assets for CGS and the Cowlitz Falls Hydroelectric Project are included in Nonfederal generation. Related assets for terminated nonfederal generation are included in Regulatory assets. (See Note 5, Effects of Regulation.)

During fiscal years 2023 and 2022, BPA recorded gains of $0 and $2.2 million when certain Energy Northwest debt was extinguished via the issuance of long-term debt. BPA recorded no such gains during fiscal year 2021.

Energy Northwest debt of $3.24 billion is callable, in whole or in part, at Energy Northwest's option with the approval of BPA, on call dates between July 2024 and July 2033 at 100% of the principal amount.

As of Sept. 30, 2023, and 2022, Energy Northwest could borrow $110 million under a line-of-credit borrowing arrangement with a banking institution. As of Sept. 30, 2023, and 2022, Energy Northwest had no amounts outstanding on this line of credit.

Lease-Purchase Program

Under the Lease-Purchase Program, BPA has incurred financial liabilities for lease-purchase transactions with certain third-party entities. These transactions are primarily with the Port of Morrow, a port district located in Morrow County, Oregon, and the Idaho Energy Resources Authority (IERA), an independent public instrumentality of the State of Idaho, for transmission facilities, including lines, substations and general plant assets. These financial liabilities are paid from the rental payments made by BPA. The facilities are not security for the payment of these obligations. The lease-purchase agreements contain provisions that allow BPA to purchase the related assets at any time during each lease term for a bargain purchase price plus the value of the related outstanding debt instrument.

Under the Lease-Purchase Program, BPA consolidates one special purpose corporation, Northwest Infrastructure Financing Corporation, or NIFC. (See Note 9, Variable Interest Entities.) As of Sept. 30, 2023, and 2022, the NIFC had $119.6 million of bonds outstanding, including debt issuance costs. The rental payments from BPA are pledged to the payment of the debt, but the facilities do not secure the debt. The NIFC bonds are reported as NIFC debt and are subject to redemption by NIFC, in whole or in part, at any date, at the higher of the principal amount of the bonds or the present value of the bonds discounted using the U.S. Treasury rate plus a premium of 12.5 basis points.

On the Combined Balance Sheets, the Lease-Purchase liability and NIFC debt are included in Nonfederal debt. The related assets are included in Utility plant and in Deferred charges and other for unspent funds held in trust accounts outside the Bonneville Fund.

Finance lease liability

Included among this liability are finance lease agreements for transmission lines and equipment. The related assets are recorded as completed plant. For additional information regarding finance leases, see Note 4, Leases.

Other financial liability

This agreement is with a transmission customer. BPA is deemed the accounting owner of the assets, which are included in Utility plant on the Combined Balance Sheets. The agreement contains provisions that allow BPA to purchase the related assets at any time during the contract term, with ownership transferring to BPA at the end of the term.

Customer prepaid power purchases

During fiscal year 2013, BPA entered into agreements with four regional COUs for the advance payment of portions of their power purchases. Under this program, customers purchased prepaid power in blocks through fiscal year 2028. For each block purchased, BPA repays the prepayment, with interest, as monthly fixed credits on the customers' power bills.

In March 2013, BPA received $340 million representing $474.3 million in scheduled credits for blocks purchased by customers. BPA accounts for the prepayment proceeds as a financing transaction and reports the value of the obligations associated with the fixed credits as a prepayment liability. Interest expense is recognized using a weighted-average effective interest rate of 4.5%. The prepaid liability is reduced and the credits are applied as power is delivered through fiscal year 2028.

FEDERAL DEBT AND APPROPRIATIONS

Borrowings from U.S. Treasury

BPA is authorized by Congress to issue and sell bonds to the U.S. Treasury and to have outstanding at any time up to $13.70 billion aggregate principal amount of bonds. Beginning in fiscal year 2028, an additional $4.00 billion of U.S. Treasury borrowing authority will be available. Of the $13.70 billion in borrowing authority currently available, $1.25 billion is available for electric power conservation and renewable resources, including capital investment at the FCRPS hydroelectric facilities owned by the USACE and Reclamation, and $12.45 billion is available for BPA's transmission capital program and to implement BPA's authorities under the Northwest Power Act. Of the total U.S. Treasury borrowing authority available at any one time ($13.70 billion through fiscal year 2027 and $17.70 billion beginning in fiscal year 2028), $750 million can be issued to finance Northwest Power Act-related expenses. The interest on BPA's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. Bonds can be issued with call options.

As of Sept. 30, 2023, and 2022, no bonds outstanding were related to Northwest Power Act expenses.

As of Sept. 30, 2023, $495.2 million of variable-rate bonds are callable by BPA at par value on their interest repricing dates, which occurs every three or six months. The remaining $5.29 billion of bonds are callable by BPA at a premium or discount, which is calculated based on the current government agency rates for the remaining term to maturity at the time the bonds are called. As of Sept. 30, 2022, $626.1 million of variable-rate bonds were outstanding.

In fiscal year 2023, BPA called $322.9 million of bonds it had previously issued to the U.S. Treasury. As a result, BPA recognized a net gain of $5 million to Other, net in the Combined Statements of Revenues and Expenses. BPA recorded no such gains or losses during fiscal years 2022 and 2021.

Federal appropriations

Federal appropriations reflect the responsibility that BPA has to repay the U.S. Treasury for congressionally appropriated amounts in the FCRPS. Federal appropriations repayment obligations consist of the remaining unpaid power portion of USACE and Reclamation capital investments funded through congressional appropriations. These include appropriations for the Columbia River Fish Mitigation program as allocated to the power purpose of the USACE's FCRPS hydroelectric projects. BPA's repayment obligation begins when capital investments are completed and placed into service, unless directed otherwise by specific legislation.

BPA is obligated to establish rates to repay appropriations for federal generation and transmission plant investments within a specified repayment period, which is the reasonably expected service life of the facilities, not to exceed 50 years. Federal appropriations may be repaid early without penalty at their par value (i.e., carrying value for federal appropriations) as part of BPA's payment to the U.S. Treasury. BPA repaid appropriations earlier than their due dates in fiscal years 2023 and 2022. BPA establishes schedules for the repayment of federal appropriations when it establishes its power and transmission rates. These schedules can change depending on whether appropriations have been prepaid or deferred. Interest on appropriated amounts begins accruing when the related assets are placed into service, unless repayment obligation is deferred by specific legislation.

As of Sept. 30 — millions of dollars	Maturing Nonfederal debt excluding finance leases	Future minimum lease payments under finance leases	Borrowings from U.S. Treasury	Federal appropriations	Total
2024	$ 557.0	$ 10.0	$ 199.0	$ —	$ 766.0
2025	654.0	9.5	144.0	—	807.5
2026	580.2	7.8	127.0	—	715.0
2027	527.5	7.1	175.0	—	709.6
2028	677.4	6.9	299.8	—	984.1
2029 and thereafter	4,720.7	170.3	4,839.0	1,597.6	11,327.6
Total	$ 7,716.8	$ 211.6	$ 5,783.8	$ 1,597.6	$ 15,309.8
Less: Executory costs	2.7	—	—	—	2.7
Less: Amount representing interest	714.8	107.2	—	—	822.0
Less: Unamortized debt issuance cost	16.1	—	—	—	16.1
Plus: Unamortized premiums	303.5	—	—	—	303.5
Present value of debt	7,286.7	104.4	5,783.8	1,597.6	14,772.5
Less: Current portion	500.6	4.9	199.0	—	704.5
Long-term debt	$ 6,786.1	$ 99.5	$ 5,584.8	$ 1,597.6	$ 14,068.0

FAIR VALUE OF DEBT AND APPROPRIATIONS

See Note 13, Fair Value Measurements, for a comparison of carrying value to fair value for debt. Due to the current par value call provision on BPA's federal appropriations, the fair value of BPA's federal appropriations is equal to the carrying value. This call provision allows BPA to prepay appropriations repayment obligations without premiums or a mark-to-market adjustment.

9. Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional financial support or whose equity investors lack characteristics of a controlling financial interest. An enterprise that has a controlling interest is known as the VIE's primary beneficiary and is required to consolidate the VIE.

Management reviews executed lease-purchase agreements with nonfederal entities for VIE accounting impacts. BPA has determined that NIFC is a VIE and that BPA is the primary beneficiary of NIFC. As such, this entity is consolidated. The key factors in this determination are BPA's ability to take contractual actions that significantly impact the economic, commercial and operating activities of NIFC and BPA's obligation to absorb losses that could be significant to NIFC. Additionally, BPA's lease-purchase agreement with NIFC obligates BPA to absorb the operational and commercial risks, and thus potentially significant benefits or losses associated with the underlying transmission facilities. BPA also has exclusive use and control of the facilities during the lease period and has indemnified NIFC for all construction and operating risks associated with its transmission facilities.

Amounts related to NIFC include Lease-Purchase trust funds and other assets of $20.6 million and $20.5 million and Nonfederal debt of $119.1 and $119 million as of Sept. 30, 2023, and 2022, respectively. BPA has also entered into lease-purchase agreements with Port of Morrow and IERA, which are nonfederal entities. These entities are governmental and, in accordance with VIE accounting guidance, are therefore not consolidated into the FCRPS financial statements. (See Note 8, Debt and Appropriations.)

BPA has entered into power purchase agreements with wind farm-related VIEs, which, because of their pricing arrangements, provide that BPA absorb commodity price risk from the perspective of the counterparty entities. However, BPA management has concluded that in no instance does BPA have the power to control the most significant operating and maintenance activities of these entities. Therefore, BPA is not the primary beneficiary and does not consolidate these entities. Additionally, BPA does not provide, and does not plan to provide, any additional financial support to these entities beyond what BPA is contractually obligated to pay. Thus, BPA has no exposure to loss on contracts with these VIEs. Expenses related to VIEs for which BPA is not the primary beneficiary were $9.5 million, $16.5 million and $20.6 million in fiscal years 2023, 2022 and 2021, respectively. These expenses were recorded to operations and maintenance as BPA management considers the related purchases to be part of the FCRPS resource pool.

10. Residential Exchange Program

BACKGROUND

In 1981 and as provided in the Northwest Power Act, BPA began to implement the Residential Exchange Program (REP) through various contracts with eligible regional utility customers. BPA's implementation of the REP has been the subject of various litigations and settlement agreements.

REP SCHEDULED AMOUNTS

As of Sept. 30 — millions of dollars		
2024	$	273.6
2025		273.6
2026		286.1
2027		286.1
2028		286.1
Subtotal of annual payments		1,405.5
Less: Discount for present value		106.3
IOU exchange benefits	$	1,299.2

2012 RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT

Beginning in April 2010, over 50 litigants and other regional parties entered into mediation to resolve numerous disputes over the REP. In fiscal year 2011 the parties reached a final settlement agreement – the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement). As a result of the settlement, BPA recorded an associated long-term IOU exchange benefits liability and corresponding regulatory asset of $3.07 billion. Under the 2012 REP Settlement Agreement, the IOUs' REP benefits were determined for fiscal years 2012 - 2028 (also referred to herein as Scheduled Amounts). The Scheduled Amounts started at $182.1 million for fiscal year 2012 and increase over time to $286.1 million for fiscal year 2028. As provided in the 2012 REP Settlement Agreement, the Scheduled Amounts are established for each IOU based on the IOU's average system cost, its residential exchange load and BPA's applicable Priority Firm Exchange rate. The Scheduled Amounts total $4.07 billion over the 17-year period through fiscal year 2028, with remaining Scheduled Amounts as of Sept. 30, 2023, totaling $1.41 billion. Amounts recorded of $1.30 billion at Sept. 30, 2023, represent the present value of future cash outflows for these IOU exchange benefits.

11. Deferred Credits and Other

Deferred Credits and Other include the following items:

As of Sept. 30 — millions of dollars	2023	2022
Interconnection agreements	$ 248.3	$ 203.8
Phase 2 Implementation Plan (P2IP) Settlement Agreement	242.8	—
Deferred project revenue funded in advance	144.8	141.5
Third AC Intertie capacity agreements	82.6	86.1
Operating leases	75.0	66.7
Unearned revenue from customer deposits	66.0	37.8
Service deposits	48.2	58.1
Federal Employees’ Compensation Act	17.8	18.9
Fiber optic leasing fees	5.9	6.4
Other	2.6	3.9
Derivative instruments	1.8	11.0
Total	$ 935.8	$ 634.2

“**Interconnection agreements**” are advances for requested new network upgrades and interconnections. These advances accrue interest and will be returned as cash or credits against future transmission service on the new or upgraded lines.

“**Phase 2 Implementation Plan (P2IP) Settlement Agreement**” represents the undiscounted long-term portion of future payments to be made to certain Upper Columbia River tribes as agreed to in the P2IP Settlement Agreement signed in September 2023. Per the terms of the agreement, BPA will provide $10 million per year, beginning in fiscal year 2024 for the 20-year duration of the agreement, for a total of $200 million (adjusted for inflation). These funds are to be used to test the feasibility of, and ultimately reintroduce salmon in blocked habitats in the Upper Columbia River Basin. The Settlement Agreement became effective in October 2023 upon the dismissal of the related tribal litigation.

“Deferred project revenue funded in advance” consists of third-party advances received where BPA will own the resulting transmission assets. The balance is amortized as other revenue not with customers over the life of the assets, so that the balance prevents any stranded costs in case of impairment as prescribed by the transmission rate process.

“**Third AC Intertie capacity agreements**” reflect unearned revenue from customers related to the Third AC Intertie transmission line capacity project. Revenue is recognized over an estimated 51-year life of the related assets, which are generally added and retired each year. (See Note 2, Revenue Recognition.)

“**Operating leases**” consists of long-term lease liabilities. (See Note 4, Leases.)

“**Unearned revenue from customer deposits**” consists of advances received from customers for projects or studies undertaken at their request. Revenue is recognized as expenditures are incurred. (See Note 2, Revenue Recognition.)

“**Service deposits**” reflect required deposits for BPA products or services. The majority of these amounts are expected to be returned to the customer after a period of service. In certain cases, the deposits are considered prepayments, in which case they are recognized as revenue as per terms of the contract.

“**Federal Employees’ Compensation Act**” reflects the actuarial estimated amount of future payments for current recipients of BPA’s worker compensation benefits.

“**Fiber optic leasing fees**” reflect unearned revenue related to the leasing of fiber optic cables. BPA recognizes revenue over the lease terms, which extend through 2024. (See Note 2, Revenue Recognition.)

“**Derivative instruments**” reflect the unrealized loss of the derivative portfolio, which primarily includes physical power purchase and sale transactions.

12. Risk Management and Derivative Instruments

BPA is exposed to various forms of market risks related to commodity prices and volumes, counterparty credit and interest rates. Non-performance risk, which includes credit risk, is described in Note 13, Fair Value Measurements. BPA has formal risk management processes in place to manage agency risks, including the use of derivative instruments. The following sections describe BPA's exposure to and management of certain risks.

RISK MANAGEMENT

Due to the operational risk posed by fluctuations in river flows and electricity market prices, net revenues that result from underlying surplus or deficit energy positions are inherently uncertain. BPA's Risk Oversight Committee has responsibility for the oversight of market risk and determines the transactional risk policy and control environment at BPA. Through simulation and analysis of the hydro supply system, experienced business and risk managers install market price risk measures to capture additional market-related risks, including credit and event risk.

COMMODITY PRICE RISK AND VOLUMETRIC RISK

BPA has exposure to commodity price risk through fluctuations in electricity market prices that affect the value of energy bought and sold. Volumetric risk is the uncertainty of energy production from the hydro system. The combination of the two results in net revenue uncertainty. BPA routinely models commodity price risk and volumetric risk through parametric calculations, Monte Carlo simulations and general market observations to derive net revenues at risk, mark-to-market valuations, value at risk and other metrics as appropriate. These metrics capture the uncertainty around single point forecasts in order to monitor changes in the revenue risk profile from changes in market price, market price volatility and forecasted hydro generation. BPA measures and monitors the output of these methods on a regular basis. In order to mitigate revenue uncertainty that is beyond BPA's risk tolerance, BPA enters into short-term and long-term purchase and sale contracts by using instruments such as forwards, futures, swaps, and options.

CREDIT RISK

Credit risk relates to the loss that might occur as a result of counterparty non-performance. BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure. To further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, and cash in the form of prepayments, deposits or escrow funds, from some counterparties. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. BPA uses scoring models, publicly available financial information and external ratings from major credit rating agencies to determine appropriate levels of credit for its counterparties.

During fiscal year 2023, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2023, BPA had $66 million in credit exposure related to purchase and sale contracts after taking into account netting rights. Of this $66 million, $61.6 million was related to investment grade counterparties and $4.3 million was related to sub-investment grade counterparties who provided letters of credit. The letters of credit serve as a guarantee arrangement and mitigate BPA's credit risk exposure to these counterparties.

INTEREST RATE RISK

BPA has the ability to issue variable rate bonds to the U.S. Treasury. BPA may manage the interest rate risk presented by variable rate U.S. Treasury debt by holding U.S. Treasury security investments with a similar maturity profile. Such investments may earn interest that is correlated, but typically lower than, the interest rate paid on U.S. Treasury variable rate debt.

DERIVATIVE INSTRUMENTS

Commodity Contracts

BPA's forward electricity contracts are eligible for the normal purchases and normal sales exception if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the derivative accounting definition of capacity described in the derivatives and hedging accounting guidance. Transactions for which BPA has elected the normal purchases and normal sales exception are not recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts are delivered and settled.

For derivative instruments recorded at fair value, BPA offsets unrealized gains and losses as Regulatory assets and Regulatory liabilities on the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses when the contracts are delivered and settled.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. (See Note 13, Fair Value Measurements.)

As of Sept. 30, 2023, the derivative commodity contracts recorded at fair value totaled 3.8 million megawatt hours (MWh), gross basis, with delivery months extending to September 2024.

On the Combined Balance Sheets, BPA reports net fair value amounts of derivative instruments subject to a master netting arrangement (excluding contracts designated as normal purchases or normal sales) in accordance with ASC 210 and 815. In the event of default or termination, contracts with the same counterparty are offset and net settle through a single payment. BPA does not offset cash collateral against recognized derivative instruments with the same counterparty under the master netting arrangements.

If reported gross, BPA's derivative position would have resulted in assets of $51.9 million and $56.5 million, and liabilities of $2.2 million and $12.1 million as of Sept. 30, 2023, and 2022, respectively. (See Note 5, Effects of Regulation.)

13. Fair Value Measurements

BPA applies fair value measurements and disclosures accounting guidance to certain assets and liabilities including assets held in trust funds, commodity derivative instruments, debt and other items. BPA maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value. Fair value is based on actively quoted market prices, if available. In the absence of actively quoted market prices, BPA seeks price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, BPA uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs.

BPA also utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value, into three broad levels:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities that BPA has the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as exchange-traded financial futures, fixed income investments, equity mutual funds and money market funds.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include certain non-exchange traded commodity derivatives and certain agency, corporate and municipal securities as part of the Lease-Purchase trust funds investments. Fair value for certain non-exchange traded derivatives is based on forward exchange market prices and broker quotes adjusted and discounted. Lease-Purchase trust funds investments are based on a market input evaluation pricing methodology using a combination of observable market data such as current market trade data, reported bid/ask spreads, and institutional bid information.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

BPA includes non-performance risk when calculating fair value measurements. This includes a credit risk adjustment based on the credit spreads of BPA’s counterparties when in an unrealized gain position. BPA’s assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at Sept. 30, 2023, and 2022. There were no transfers between Level 2 and Level 3 during fiscal years 2023 and 2022.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2023 — millions of dollars

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity securities	$ 396.1	$ —	$ —	$ 396.1
Debt securities	66.4	—	—	66.4
Cash and cash equivalents	17.0	—	—	17.0
Lease-Purchase trust funds				
U.S. government obligations	—	2.6	—	2.6
Derivative instruments [1]				
Commodity contracts	0.1	40.3	11.1	51.5
Transmission line-related receivables	—	—	10.4	10.4
Total	$ 479.6	$ 42.9	$ 21.5	$ 544.0
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ —	$ (1.8)	$ —	$ (1.8)
Total	$ —	$ (1.8)	$ —	$ (1.8)

As of Sept. 30, 2022 — millions of dollars

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity securities	$ 337.8	$ —	$ —	$ 337.8
Debt securities	59.3	—	—	59.3
Cash and cash equivalents	17.5	—	—	17.5
Lease-Purchase trust funds				
U.S. government obligations	—	0.1	—	0.1
Derivative instruments [1]				
Commodity contracts	4.0	37.9	13.5	55.4
Total	$ 418.6	$ 38.0	$ 13.5	$ 470.1
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ —	$ (10.0)	$ (1.0)	$ (11.0)
Total	$ —	$ (10.0)	$ (1.0)	$ (11.0)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other, respectively, on the Combined Balance Sheets. See Note 12, Risk Management and Derivative Instruments for more information related to BPA's risk management strategy and use of derivative instruments.

Commodity contracts assets and liabilities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of power contracts measured at fair value on a recurring basis using the California-Oregon Border (COB) forward price curves. They include power contracts delivering to illiquid trading points or contracts without available market transactions for the entire delivery period. Forward prices are considered a key component to contract valuations. All valuation pricing data is generated internally by BPA's risk management organization.

Quantitative information regarding the only significant unobservable input used in the measurement of Level 3 commodity contract assets and liabilities is presented below:

	Fair Value		Valuation Technique	Significant Unobservable Input	Range (per MWh)		
	Assets[1]	Liabilities[1]			Low	High	Weighted Average
	(in millions)						
As of Sept. 30, 2023							
Physical forward power contracts	$ 11.1	$ —	Discounted cash flow	Electricity forward price	$ 48.1	$ 183.8	$ 124.3
As of Sept. 30, 2022							
Physical forward power contracts	$ 13.5	$ (1.0)	Discounted cash flow	Electricity forward price	$ 36.2	$ 180.3	$ 112.0

[1] The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions.

The significant unobservable input listed above is used by the risk management organization to construct the fair value through the use of available market prices, broker quotes and bid/offer spreads. In periods where market prices or broker quotes are not available, the risk management organization derives monthly prices by applying seasonal shaping based on historical broker quotes and spreads. Long-term prices are derived from internally developed or commercial models with both internal and external data inputs. BPA management believes this approach maximizes the use of pricing information from external sources and is currently the best option for valuation. Significant increases or decreases in the inputs would result in significantly higher or lower fair value measurements.

Forward power prices are influenced by, among other factors, the price of natural gas, seasonality, hydro forecasts, expectations of demand growth, and planned changes in the regional generating plants.

Transmission line-related receivables classified as Level 3 consist of a set of contracts executed between BPA and IPC governing the Purchase, Sale and Security provisions related to the transfer of BPA's permitting interest share in the proposed Boardman-to-Hemingway transmission line to IPC. (For further information on this transaction, see Note 7, Deferred Charges and Other.) These contracts determine whether, when and how much of BPA's contributions towards project security, initial design and permitting will be returned to BPA.

Significant unobservable inputs related to the Transmission line-related receivable asset are the occurrence of certain contingent contractual provisions and the energization of the underlying transmission line. These assessments result in expectations concerning specific future cash flows, which are currently estimated to occur between 2026 and 2046.

The following table presents the changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

As of Sept. 30 — millions of dollars	2023	2022
Beginning Balance	$ 12.5	$ (15.2)
Changes in unrealized gains (losses)[1]	(1.4)	27.7
Transmission line-related receivables additions	10.4	—
Ending Balance	$ 21.5	$ 12.5

[1] Unrealized gains and losses are included in Regulatory assets and Regulatory liabilities on the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power, respectively, in the Combined Statements of Revenues and Expenses.

DEBT

As of Sept. 30 — millions of dollars	2023		2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Nonfederal Debt				
Nonfederal generation:				
Columbia Generating Station	$ 3,381.9	$ 3,229.6	$ 3,295.9	$ 3,182.8
Cowlitz Falls Project	52.0	56.4	56.4	61.6
Terminated nonfederal generation:				
Nuclear Project 1	837.5	832.6	824.1	832.7
Nuclear Project 3	970.6	987.1	950.3	995.0
Northern Wasco Hydro Project	3.6	3.6	5.3	5.4
Lease-Purchase Program:				
Lease-purchase liability	1,766.8	1,372.2	1,838.3	1,475.3
NIFC debt	119.1	118.7	119.0	125.6
Other financial liability	16.0	8.5	16.5	9.0
Customer prepaid power purchases	139.2	139.2	163.0	163.0
Federal debt				
Borrowings from U.S. Treasury	$ 5,783.8	$ 4,756.6	$ 5,678.7	$ 4,907.9

The fair value measurements described above are considered Level 2 in the fair value hierarchy.

The fair value of Nonfederal debt, excluding Other financial liability and Customer prepaid power purchases, is primarily based on a market input evaluation pricing methodology using a combination of market observable data such as current market trade data, reported bid/ask spreads and institutional bid information.

The fair value of Other financial liability is based upon discounted future cash flows using estimated interest rates for similar debt that could have been issued at Sept. 30, 2023, and 2022.

The opportunity to participate in the Customer prepaid power purchase program was made to a subset of BPA's power customers with repayment terms through billing credits extending to fiscal year 2028. Management believes that the customer prepaid power purchases are specific to BPA's operating environment and are nontransferable. As a result, the carrying value of customer prepaid power purchases is equal to its fair value.

The fair value of Borrowings from U.S. Treasury is based on discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2023, and 2022.

The table above does not include Finance lease liabilities, a component of BPA's nonfederal debt. See Note 8, Debt and Appropriations, for the full carrying value of BPA's debt portfolio.

14. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife and their habitats to the extent they are affected by the federal hydroelectric projects on the Columbia River and its tributaries from which BPA markets power. BPA makes expenditures and incurs other costs for fish and wildlife protection and mitigation that are consistent with the purposes of the Northwest Power Act and the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish and wildlife species that inhabit the Columbia River Basin are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA makes expenditures and incurs other costs related to power purposes to comply with the ESA and implement certain biological opinions (BiOp) prepared by the National Oceanic and Atmospheric Administration Fisheries Service and the U.S. Fish and Wildlife Service in furtherance of the ESA (including results from the Columbia River System Operations (CRSO) Environmental Impact Statement). BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp, including CRSO Environmental Impact Statement impacts, is not fixed or determinable.

As of Sept. 30, 2023, BPA has long-term fish and wildlife agreements with estimated contractual commitments of $649.3 million, which are likely to result in future expenses or regulatory assets. These agreements will expire at various dates through fiscal year 2027 and include the Columbia Basin Fish Accords extension agreements, which are described below.

BPA and its federal partners, USACE and Reclamation, have signed extension agreements with current Accords partners, namely certain states and tribes, to extend the Columbia Basin Fish Accords through Sept. 30, 2025. The Accords and associated BPA funding commitments facilitate implementation of projects that provide BPA with legal compliance actions under applicable laws, including the Northwest Power Act and Endangered Species Act, and that benefit Columbia River Basin fish and wildlife. The extension agreements commit approximately $409 million for fish and wildlife protection and mitigation, which will result in future expenses or regulatory assets.

IRRIGATION ASSISTANCE

Scheduled distributions

Years ended Sept. 30 — millions of dollars		
2024	$	8.3
2025		13.2
2026		20.7
2027		6.4
2028		11.6
2029 through 2045		174.7
Total	$	234.9

As directed by law, BPA is required to establish rates sufficient to make distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects for which the costs have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation. In establishing power rates, particular statutory provisions guide the assumptions that BPA makes as to the amount and timing of such distributions. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues when paid. Future irrigation assistance payments are scheduled to total $234.9 million over a maximum of 66 years since the time the irrigation facilities were completed and placed in service. BPA is required by the Grand Coulee Dam - Third Powerplant Act to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects to the extent the costs have been determined to be beyond the irrigators' ability to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period. Irrigation assistance excludes $40.3 million for Teton Dam, which failed prior to completion and for which BPA has no obligation to repay.

FIRM PURCHASE POWER COMMITMENTS

Years ended Sept. 30 — millions of dollars		
2024	$	49.9
2025		47.5
2026		44.5
Total	$	141.9

BPA periodically enters into long-term commitments to purchase power for future delivery. When BPA forecasts a resource shortage, based on its planned contractual obligations for a period and the historical water record for the Columbia River basin, BPA takes a variety of operational and business steps to cover a potential shortage including entering into power purchase commitments. Additionally, under BPA's current Tiered Rates Methodology and its current Regional Dialogue power sales contracts, BPA's customers may request that BPA meet their power requirements in excess of the Rate Period High Water Mark load under their contract. For these Above High Water Mark load requests, BPA may meet such requests by entering into power purchase commitments.

The preceding table includes firm purchase power agreements that are currently in place to assist in meeting expected future obligations under BPA's current long-term power sales contracts. Included are three purchases to meet load obligations in Idaho. Power purchase agreements to satisfy load obligations in Idaho utilize variable pricing. Variable pricing arrangements are based on the current market price of energy on the date of delivery. The expenses associated with the Idaho purchases were $74.9 million, $7.6 million and $83.7 million for fiscal years 2023, 2022 and 2021, respectively. BPA has several other purchase agreements with wind-powered and other generating facilities that are not included in the preceding table as payments are based on the variable amount of future energy generated and as there are no minimum payments required.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Northwest Power Act to meet the net firm power load requirements of its customers in the Pacific Northwest. BPA is authorized to help meet its net firm power load through the acquisition of electric conservation. BPA makes available a portfolio of initiatives and infrastructure support activities to its customers to ensure the conservation targets established in the Northwest Power and Conservation Council's then-current Power Plan are achieved. The Council released the 2021 Northwest Power Plan in fiscal year 2022. These initiatives and activities are often executed via conservation commitments made by BPA to its customers through agreements with utility customers and contractors that provide support in the way of energy efficiency program research, development and implementation. The timing of the payments under these commitments is not fixed or determinable, and these agreements will expire at various dates through fiscal year 2028. Conservation-related expenses are recorded to operations and maintenance expense as incurred.

1989 ENERGY NORTHWEST LETTER AGREEMENT

In 1989, BPA agreed with Energy Northwest that, in the event any participant shall be unable for any reason, or shall fail or refuse, to pay to Energy Northwest any amount due from such participant under its net billing agreement for which a net billing credit or cash payment to such participant has been provided by BPA, BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest. As of Sept. 30, 2023, and 2022, no amounts have been accrued related to this agreement.

NUCLEAR INSURANCE

BPA is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurance company established to provide insurance coverage for nuclear power plants. The insurance policies purchased from NEIL by BPA for CGS include: 1) Primary Property and Decontamination Liability Insurance; 2) Excess Property, Excess Decontamination Liability and Decommissioning Liability Insurance; and 3) NEIL I Accidental Outage Insurance.

Under each insurance policy, BPA could be subject to a retrospective premium assessment in the event that a member-insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Liability Insurance policy is $19.3 million. For the Excess Property, Excess Decontamination Liability and Decommissioning Liability Insurance policy, the maximum assessment is $7.1 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $5.7 million.

Additionally, in the event of a nuclear accident resulting in public liability losses exceeding $450 million under the Nuclear Regulatory Commission’s indemnity for public liability coverage under the Price-Anderson Act, BPA could be subject to a retrospective assessment of up to $165.9 million limited to $24.7 million per incident within one calendar year. Assessments would be included in BPA’s costs and recovered through rates. As of Sept. 30, 2023, there have been no assessments payable by BPA under any of these events.

ENVIRONMENTAL MATTERS

From time to time there are sites for which BPA, the USACE or Reclamation may be identified as potential responsible parties. Costs associated with cleanup of sites are not expected to be material to the FCRPS financial statements. As such, no material liability has been recorded.

INDEMNIFICATION AGREEMENTS

BPA, USACE and Reclamation have provided indemnifications of varying scope and terms in contracts with customers, vendors, lessors, trustees, and other parties with respect to certain matters including, but not limited to, losses arising out of particular actions taken on behalf of the FCRPS, certain circumstances related to Energy Northwest Projects, and in connection with lease-purchases. Because of the absence of a maximum obligation in the provisions, management is not able to reasonably estimate the overall maximum potential future payments. Based on historical experience and current evaluation of circumstances, management believes that as of Sept. 30, 2023, the likelihood is remote that the FCRPS would incur any significant costs with respect to such indemnities. No liability has been recorded in the financial statements with respect to these indemnification provisions.

RESERVES DISTRIBUTION CLAUSE

The Reserves Distribution Clause (RDC) is a rate adjustment mechanism that triggers if reserves for risk levels exceed certain cash on hand targets at September 30 for Power Services or Transmission Services. Terms of the RDC are discussed in the BP-24 and BP-22 rate cases, which state that the BPA Administrator shall consider amounts for investment in business-line specific purposes including debt reduction, incremental capital investment, rate reduction, or other Power- or Transmission-specific purposes determined by the Administrator.

Based on fiscal year 2023 financial results and year-end reserves for risk levels for both Power and Transmission Services, an RDC is expected to occur for application in fiscal year 2024. BPA’s Administrator will determine final amounts and use of the fiscal year 2024 Power and Transmission RDC by Dec. 15, 2023, with application of most RDC actions likely to occur between December and September of fiscal year 2024. As of Sept. 30, 2023, no liability has been accrued for the RDC.

Based upon fiscal year 2022 financial results and year-end reserves for risk levels for both Power and Transmission Services, an RDC occurred for application to fiscal year 2023 power and transmission rate levels. Final determination of the amounts and use of the fiscal year 2023 Power and Transmission RDC occurred during fiscal year 2023, and application of most RDC actions occurred between December and September of fiscal year 2023. As of Sept. 30, 2022, no liability had been accrued for the RDC.

LITIGATION

Rates

BPA's rates are frequently the subject of litigation. Most of the litigation typically involves claims that BPA's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record, or are arbitrary and capricious. It is the opinion of BPA's general counsel that if any rate were to be rejected, the remedy accorded would be a remand to BPA to establish a new rate. BPA's flexibility in establishing rates could be restricted by the rejection of a BPA rate, depending on the grounds for the rejection. BPA is unable to predict, however, what new rate it would establish if a rate were rejected. If BPA were to establish a rate that was lower than the rejected rate, a petitioner may be entitled to a refund in the amount overpaid; however, BPA is required by law to set rates to meet all of its costs. Thus, it is the opinion of BPA's general counsel that BPA may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Other

The FCRPS may be affected by various other claims, actions and complaints, including claims regarding litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts including operational changes at FCRPS federal dams that may restrict hydroelectric generation. Management is unable to predict whether the FCRPS will avoid adverse outcomes in these legal matters.

Judgments and settlements are included in FCRPS costs and recovered through rates. As of Sept. 30, 2023, no material liability has been recorded for the above legal matters.

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APPENDIX B - 2

FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION
FOR THE SIX MONTHS ENDED MARCH 31, 2024

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Federal Columbia River Power System
Combined Balance Sheets (Unaudited)
(Millions of Dollars)

	As of March 31, 2024	As of September 30, 2023
Assets		
Utility plant and nonfederal generation		
Completed plant	$ 21,922.3	$ 21,674.7
Accumulated depreciation	(8,488.9)	(8,316.0)
Net completed plant	13,433.4	13,358.7
Construction work in progress	1,929.4	1,733.1
Net utility plant	15,362.8	15,091.8
Nonfederal generation	3,412.7	3,380.0
Net utility plant and nonfederal generation	18,775.5	18,471.8
Current assets		
Cash and cash equivalents	1,342.5	2,037.9
Accounts receivable, net of allowance	53.6	84.7
Accrued unbilled revenues	311.2	282.7
Materials and supplies, at average cost	125.4	121.0
Prepaid expenses	70.2	67.9
Total current assets	1,902.9	2,594.2
Other assets		
Regulatory assets	4,102.2	4,272.4
Nonfederal nuclear decommissioning trusts	566.3	479.5
Deferred charges and other	289.5	222.0
Total other assets	4,958.0	4,973.9
Total assets	$ 25,636.4	$ 26,039.9

Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Millions of Dollars)

	As of March 31, 2024	As of September 30, 2023
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 5,432.2**	$ 5,589.1
Debt		
Federal appropriations	**1,610.7**	1,597.6
Borrowings from U.S. Treasury	**5,574.8**	5,584.8
Nonfederal debt	**6,775.8**	6,885.6
Total capitalization and long-term liabilities	**19,393.5**	19,657.1
Commitments and contingencies (See Note 14 to 2023 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	**140.2**	199.0
Nonfederal debt	**587.3**	505.5
Accounts payable and other	**655.2**	885.0
Total current liabilities	**1,382.7**	1,589.5
Other liabilities		
Regulatory liabilities	**1,572.8**	1,543.2
IOU exchange benefits	**1,165.2**	1,299.2
Asset retirement obligations	**1,093.8**	1,015.1
Deferred credits and other	**1,028.4**	935.8
Total other liabilities	**4,860.2**	4,793.3
Total capitalization and liabilities	**$ 25,636.4**	$ 26,039.9

Federal Columbia River Power System

Combined Statements of Revenues and Expenses (Unaudited)

(Millions of Dollars)

	Three Months Ended March 31,		Fiscal Year-to-Date Ended March 31,	
	2024	2023	**2024**	2023
Operating revenues				
Sales	**$ 1,210.5**	$ 1,088.2	**$ 2,239.2**	$ 2,095.0
U.S. Treasury credits	**146.8**	107.1	**226.5**	163.0
Total operating revenues	**1,357.3**	1,195.3	**2,465.7**	2,258.0
Operating expenses				
Operations and maintenance	**621.5**	596.2	**1,180.3**	1,143.6
Purchased power	**617.4**	325.5	**846.0**	685.7
Depreciation, amortization and accretion	**216.7**	211.2	**433.4**	422.2
Total operating expenses	**1,455.6**	1,132.9	**2,459.7**	2,251.5
Net operating revenues (expenses)	**(98.3)**	62.4	**6.0**	6.5
Interest expense and other income, net				
Interest expense	**113.4**	112.3	**226.9**	223.9
Allowance for funds used during construction	**(13.1)**	(10.1)	**(26.1)**	(20.1)
Interest income	**(12.2)**	(15.3)	**(29.2)**	(30.6)
Other, net	**(1.8)**	25.9	**(8.7)**	19.8
Total interest expense and other income, net	**86.3**	112.8	**162.9**	193.0
Net expenses	**$ (184.6)**	$ (50.4)	**$ (156.9)**	$ (186.5)

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APPENDIX C

FORM OF OPINION OF ORRICK, HERRINGTON & SUTCLIFFE LLP

(Date of Closing)

Port of Morrow
2 Marine Drive
P.O. Box 200
Boardman, Oregon 97818

Re: Port of Morrow
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 9)
Series 2024 (Federally Taxable)

Ladies and Gentlemen:

We have acted as special counsel to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") in connection with the issuance by the Port of Morrow (the "Issuer") of $76,020,000.00 aggregate principal amount of the Issuer's Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9), Series 2024 (Federally Taxable) (the "Series 2024 Bonds"), issued pursuant to an Indenture of Trust, dated as of June 1, 2024 (the "Indenture"), between the Issuer and U.S. Bank Trust Company, National Association, as trustee (the "Trustee"). The Series 2024 Bonds are issued primarily to finance the costs of acquisition of certain transmission facilities to be owned by the Issuer and leased to Bonneville pursuant to the Lease-Purchase Agreement, dated June 13, 2024 (the "Lease-Purchase Agreement"), between the Issuer and Bonneville. Capitalized terms not otherwise defined herein shall have the meanings ascribed to such terms in the Indenture.

In such connection, we have reviewed the Indenture, the Lease-Purchase Agreement, opinions of counsel to Bonneville, the Trustee and the Issuer, certain resolutions of the Issuer, certificates of the Issuer, the Trustee, Bonneville and others and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein, including the judicial validation the Issuer received pursuant to an Order, dated March 15, 2012, which, among other things, confirms the valid, legal and binding effect of the proceedings of the Issuer providing for and authorizing the issuance, sale, execution and delivery of the Series 2024 Bonds and the funding of the Project. With respect to the due organization and existence of the Issuer and the adoption of the authorizing resolution of the Issuer related to the Series 2024 Bonds, we have relied upon the opinion of Monahan, Grove & Tucker.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after original delivery of the Series 2024 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 Series 2024 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 Series 2024 Bonds has concluded with their issuance, and we disclaim any obligation to update this letter.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Issuer.

We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in such documents, and of the legal conclusions contained in the opinions referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Lease-Purchase Agreement.

We call attention to the fact that the rights and obligations under the Series 2024 Bonds, Indenture and the Lease-Purchase Agreement 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 port districts in the State of Oregon. We express no opinion with respect to any indemnification, contribution, liquidated damages, penalty (including any remedy deemed to constitute or having 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, nor do we express any opinions with respect to the state or quality of title to or interest in any of the real or personal property described in or as subject to the lien of the Indenture or the Lease-Purchase Agreement or the accuracy or sufficiency of the description contained therein of, or the remedies available to enforce liens on, any such property. 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 or other offering material relating to the Series 2024 Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Series 2024 Bonds constitute the valid and binding limited recourse obligations of the Issuer, payable solely from the Trust Estate.

2. The Indenture constitutes the valid and binding obligation of the Issuer. The Indenture creates the valid pledge of the Trust Estate, subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture.

3. The Lease-Purchase Agreement constitutes the valid and binding agreement of the Issuer.

4. Interest on the Series 2024 Bonds is not excluded from gross income for U.S. federal income tax purposes pursuant to Section 103 of the U.S. Internal Revenue Code of 1986, as amended. Interest on the Series 2024 Bonds is exempt from State of Oregon personal income taxes. 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 Series 2024 Bonds.

Very truly yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

APPENDIX D

FORM OF CONTINUING DISCLOSURE CERTIFICATE

CONTINUING DISCLOSURE CERTIFICATE

$76,020,000
PORT OF MORROW, OREGON
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 9)
Series 2024

This Continuing Disclosure Certificate (the "Certificate") is executed and delivered by the Bonneville Power Administration ("Bonneville") as the obligated person for whom financial and operating data is presented in the official statement for the Port of Morrow, Oregon (the "Issuer") Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9) Series 2024 (the "Bonds").

Section 1. Purpose of Certificate. This Certificate is being executed and delivered by Bonneville for the benefit of the holders of the Bonds and to assist the underwriters of the Bonds in complying with paragraph (b)(5) of the United States Securities and Exchange Commission Rule 15c2-12 (17 C.F.R. § 240.15c2-12) as amended (the "Rule"). This Certificate constitutes Bonneville's written undertaking for the benefit of the owners of the Bonds as required by paragraph (b)(5) of the Rule.

Section 2. Definitions. Unless the context otherwise requires, the terms defined in this Section shall, for purposes of this Certificate, have the meanings herein specified.

"Beneficial Owner" means any person who has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of any Bonds, including persons holding Bonds through nominees or depositories.

"BPA Annual Information" means financial information and operating data generally of the type included in Appendix A of the Official Statement under the heading "POWER SERVICES" in the tables titled "Bonneville Power Services' Ten Largest Customers by Sales" and "Historical Average PF Preference Rates," under the heading "TRANSMISSION SERVICES" in the table titled "Transmission Services' Ten Largest Customers By Sales," and under the heading "BONNEVILLE FINANCIAL OPERATIONS" in the tables titled "Historical Capital Spending by Program by Fiscal Year," "Historical Capital Funding by Source and Fiscal Year," "Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow," "Federal System Statement of Revenues and Expenses," "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments" and "Bonneville's Fiscal Year-End Financial Reserves."

"Commission" means the United States Securities and Exchange Commission.

"FCRPS" means the Federal Columbia River Power System.

"FCRPS Fiscal Year" means the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year end is changed, Bonneville shall provide written notice of such change to the MSRB.

"Financial Obligation" means a (i) debt obligation: (ii) derivative instrument entered into in connection with, or pledged as security or source of payment for, an existing or planned debt offering; or (iii) guarantee of (i) or (ii) above. Financial Obligation shall not include municipal securities as to which a final official statement has been provided to the MSRB consistent with the Rule.

"MSRB" means the United States Municipal Securities Rulemaking Board or any successor to its functions.

"Official Statement" means the final official statement for the Bonds dated June 6, 2024.

"Rule" means the Commission's Rule 15c2-12 under the Securities Exchange Act of 1934, as it has been and may be amended.

Section 3. Financial Information. Bonneville agrees to provide or cause to be provided to the MSRB, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2024:

i. the BPA Annual Information for the FCRPS Fiscal Year; and

ii. annual financial statements of the FCRPS for the FCRPS Fiscal Year, prepared in accordance with generally accepted accounting principles; and

iii. if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville will notify the Issuer when the financial information in this section has been provided to the MSRB.

Bonneville agrees to notify the MSRB in a timely manner of any failure to provide the information described in Section 3 on or prior to the date set forth in the preceding paragraph.

Section 4. Events Notices. (a) Bonneville agrees to provide to the MSRB and the Issuer in a timely manner not in excess of ten business days after the occurrence of the event, notice of any of the following events with respect to the Bonds:

1. principal and interest payment delinquencies;

2. non-payment related defaults, if material;

3. unscheduled draws on debt service reserves reflecting financial difficulties;

4. unscheduled draws on credit enhancements reflecting financial difficulties;

5. substitution of credit or liquidity providers or their failure to perform;

6. adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds;

7. modifications to the rights of Bondholders, if material;

8. bond calls, if material, and tender offers;

9. defeasances;

10. release, substitution or sale of property securing repayment of the Bonds, if material;

11. rating changes;

12. bankruptcy, insolvency, receivership or similar event of the obligated person (Note: For the purposes of the event identified in this paragraph 12, 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 governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person);

13. 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, if material;

14. appointment of a successor or additional trustee or the change of name of a trustee, if material;

15. incurrence of a Financial Obligation of Bonneville, if material, or agreement to covenants, events of default, remedies, priority rights, or similar terms of a Financial Obligation of Bonneville, any of which affect security holders, if material;

16. default, event of acceleration, termination event, modification of terms, or similar events under the terms of the Financial Obligation of Bonneville, any of which reflect financial difficulties.

(b) Bonneville intends to comply with the events described in items 15 and 16 listed above, and the definition of Financial Obligation in Section 2, with reference to the Rule, any other applicable federal securities law and the guidance provides 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 to the amendments to the Rule effected by the 2018 Release.

Section 5. Termination. Bonneville's obligations to provide notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Bonds. In addition, Bonneville may terminate all or any portion of its obligations under this Certificate if Bonneville (a) obtains an opinion of nationally recognized bond counsel to the effect that those portions of the Rule which require this Certificate, or any provision of this Certificate, are invalid, have been repealed retroactively or otherwise do not apply to the Bonds; and (b) notifies the MSRB of such opinion and the termination of its obligations under this Certificate.

Section 6. Amendment. Notwithstanding any other provision of this Certificate, Bonneville may amend this Certificate, provided that the following conditions are satisfied:

A. If the amendment relates to the provisions of Sections 3 or 5 hereof, it 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 Bonneville with respect to the Bonds, or the type of business conducted; and,

B. If this Certificate, as amended, would, in the opinion of nationally recognized bond counsel, have complied with the requirements of the Rule at the time of the original issuance of the Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

C. The amendment either (i) is approved by the owners of the Bonds pursuant to the terms of the governing instrument at the time of the amendment or (ii) does not materially impair the interests of the owners or Beneficial Owners of the Bonds as determined by a party unaffiliated with the obligated person.

In the event of any amendment of a provision of this Certificate, Bonneville shall describe such amendment in its next annual filing pursuant to Section 3 of this Certificate, and shall include, as applicable, a narrative explanation of the reason for the amendment and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of the amendment shall be given in the same manner as for a listed event under Section 4 hereof, and (ii) the annual report for the first fiscal year that is affected by the change in accounting principles should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Section 7. Bond Owner's Remedies Under This Certificate. The right of any owner of Bonds or Beneficial Owner of Bonds to obtain legal redress for Bonneville's failure to comply with provisions of this Certificate, or for any breach or default by Bonneville of this Certificate, shall not include monetary damages and any failure by Bonneville to comply with the provisions of this Certificate shall not be an event of default with respect to the Bonds. Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Certificate. Any owner of Bonds or Beneficial Owner of Bonds shall have only such other rights and remedies available to it under federal law with respect to Bonneville.

Section 8. Form of Information. All information required to be provided under this certificate will be provided in an electronic format as prescribed by the MSRB and with the identifying information prescribed by the MSRB.

Section 9. Submitting Information Through EMMA. So long as the MSRB continues to approve the use of the Electronic Municipal Market Access ("EMMA") continuing disclosure service, any information required to be provided to the MSRB under this Certificate may be provided through EMMA. As of the date of this Certificate, the web portal for EMMA is emma.msrb.org.

Section 10. Choice of Law. This Certificate shall be governed by and construed in accordance with federal law, including federal securities laws and official interpretations thereof.

Dated as of the 13th day of June, 2024.

Bonneville Power Administration

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Authorized Official

APPENDIX E

DTC BOOK-ENTRY SYSTEM AND GLOBAL CLEARANCE PROCEDURE

The information set out below is subject to any change in or reinterpretation of the rules, regulations and procedures of DTC, Euroclear or Clearstream Banking (DTC, Euroclear and Clearstream Banking together, the "Clearing Systems") currently in effect. The information in this section concerning the Clearing Systems has been obtained from sources that the Issuer believes to be reliable, but none of the Issuer, Bonneville, the Municipal Advisor or the Underwriters take any responsibility for the accuracy, completeness or adequacy of the information in this section. Investors wishing to use the facilities of any of the Clearing Systems are advised to confirm the continued applicability of the rules, regulations and procedures of the relevant Clearing System. Neither the Issuer nor Bonneville will have any responsibility or liability for any aspect of the records relating to, or payments made on account of, beneficial ownership interests in the Series 2024 Bonds held through the facilities of any Clearing System or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests. The current "Rules" applicable to DTC are on file with the Securities and Exchange Commission and the current "Procedures" of DTC to be followed in dealing with DTC Participants are on file with DTC. Capitalized terms used but not defined in this Appendix D will have the definitions given to such terms in the forepart of this Official Statement.

THE ISSUER WILL HAVE NO RESPONSIBILITY OR OBLIGATIONS TO DIRECT PARTICIPANTS (DEFINED HEREIN) OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR DIRECT PARTICIPANTS, INDIRECT PARTICIPANTS OR BENEFICIAL OWNERS.

SO LONG AS CEDE & CO. IS THE REGISTERED OWNER OF THE SERIES 2024 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE BONDHOLDERS OR REGISTERED OWNERS OF THE SERIES 2024 BONDS SHALL MEAN CEDE & CO. AND SHALL NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2024 BONDS.

DTC Book-Entry Only System

The Depository Trust Company ("DTC"), New York, New York, will act as securities depository for the Series 2024 Bonds. The Series 2024 Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate will be issued for each maturity of the Series 2024 Bonds in the aggregate principal amount of such maturity, and will be deposited with DTC. If, however, the aggregate principal amount of any such maturity exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount, and an additional certificate will be issued with respect to any remaining principal amount of such maturity. 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"). The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission ("SEC"). More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Series 2024 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2024 Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2024 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 Series 2024 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial

Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Series 2024 Bonds, except in the event that use of the book-entry-only system for the Series 2024 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2024 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of the Series 2024 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2024 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2024 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Series 2024 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the Series 2024 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2024 Bond documents. For example, Beneficial Owners of Series 2024 Bonds may wish to ascertain that the nominee holding the Series 2024 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the Trustee and request that copies of notices be provided directly to them. THE ISSUER, BONNEVILLE AND THE TRUSTEE WILL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT AND INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO THE SERIES 2024 BONDS.

Redemption notices will be sent to DTC. If less than all of the Series 2024 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Series 2024 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 the Series 2024 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Series 2024 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee, on payable dates 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 Trustee, or the Issuer, 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 Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the Series 2024 Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2024 Bonds are required to be printed and delivered as described in the Indenture.

The Issuer, at the direction of Bonneville, may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, Series 2024 Bond certificates will be printed and delivered to DTC.

THE ISSUER, THE TRUSTEE, BONNEVILLE AND THE UNDERWRITERS SHALL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO ANY DIRECT OR INDIRECT PARTICIPANT, ANY BENEFICIAL OWNER OR ANY OTHER PERSON CLAIMING A BENEFICIAL OWNERSHIP INTEREST IN THE SERIES 2024 BONDS UNDER OR THROUGH DTC OR ANY DTC PARTICIPANT, OR ANY OTHER PERSON WHICH IS NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A HOLDER, WITH RESPECT TO THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT; THE PAYMENT BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF ANY AMOUNT IN RESPECT OF THE PRINCIPAL OF, PREMIUM, IF ANY, OR INTEREST ON THE SERIES 2024 BONDS; ANY NOTICE WHICH IS PERMITTED OR REQUIRED TO BE GIVEN TO OWNERS UNDER THE INDENTURE; THE SELECTION BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF

ANY PERSON TO RECEIVE PAYMENT IN THE EVENT OF A PARTIAL REDEMPTION OF THE SERIES 2024 BONDS; ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS AN OWNER; OR ANY OTHER PROCEDURES OR OBLIGATIONS OF DTC UNDER THE BOOK-ENTRY-ONLY SYSTEM.

SO LONG AS CEDE & CO. (OR SUCH OTHER NOMINEE AS MAY BE REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC) IS THE REGISTERED OWNER OF THE SERIES 2024 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS OR OWNERS OR REGISTERED HOLDERS OR REGISTERED OWNERS OF THE SERIES 2024 BONDS MEANS CEDE & CO., AS AFORESAID, AND DOES NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2024 BONDS.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2024 Bonds, payment of principal, interest and other payments on the Series 2024 Bonds to Direct and Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Series 2024 Bonds and other related transactions by and between DTC, the Direct and Indirect Participants and the Beneficial Owners is based solely on information provided by DTC. Accordingly, no representations can be made concerning these matters, and neither the Direct nor Indirect Participants nor the Beneficial Owners should rely on the foregoing information with respect to such matters, but should instead confirm the same with DTC.

Euroclear and Clearstream Banking

Euroclear and Clearstream Banking each hold securities for their customers and facilitate the clearance and settlement of securities transactions by electronic book-entry transfer between their respective account holders. Euroclear and Clearstream Banking provide various services including safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Euroclear and Clearstream Banking also deal with domestic securities markets in several countries through established depositary and custodial relationships. Euroclear and Clearstream Banking have established an electronic bridge between their two systems across which their respective participants may settle trades with each other.

Euroclear and Clearstream Banking customers are worldwide financial institutions, including underwriters, securities brokers and dealers, banks, trust companies and clearing corporations. Indirect access to Euroclear and Clearstream Banking is available to other institutions that clear through or maintain a custodial relationship with an account holder of either system, either directly or indirectly.

Clearing and Settlement Procedures

The Series 2024 Bonds sold in offshore transactions will be initially issued to investors through the book-entry facilities of DTC, or Clearstream Banking and Euroclear in Europe if the investors are participants in those systems, or indirectly through organizations that are participants in the systems. For any of such Bonds, the record holder will be DTC's nominee. Clearstream Banking and Euroclear will hold omnibus positions on behalf of their participants through customers' securities accounts in Clearstream Banking's and Euroclear's names on the books of their respective depositories.

The depositories, in turn, will hold positions in customers' securities accounts in the depositories' names on the books of DTC. Because of time zone differences, the securities account of a Clearstream Banking or Euroclear participant as a result of a transaction with a participant, other than a depository holding on behalf of Clearstream Banking or Euroclear, will be credited during the securities settlement processing day, which must be a business day for Clearstream Banking or Euroclear, as the case may be, immediately following the DTC settlement date. These credits or any transactions in the securities settled during the processing will be reported to the relevant Euroclear participant or Clearstream Banking participant on that business day. Cash received in Clearstream Banking or Euroclear as a result of sales of securities by or through a Clearstream Banking participant or Euroclear participant to a Direct Participant, other than the depository for Clearstream Banking or Euroclear, will be received with value on the DTC settlement date but will be available in the relevant Clearstream Banking or Euroclear cash account only as of the business day following settlement in DTC.

Transfers between participants will occur in accordance with DTC rules. Transfers between Clearstream Banking participants or Euroclear participants will occur in accordance with their respective rules and operating procedures. Cross-market transfers between persons holding directly or indirectly through DTC, on the one hand, and directly or indirectly through Clearstream Banking participants or Euroclear participants, on the other, will be effected in DTC in accordance with DTC rules on behalf of the relevant European international clearing system by the relevant depositories; however, cross-market transactions will require delivery of instructions to the relevant European international clearing system by the counterparty in the system in accordance with its rules and procedures and within its established deadlines in European time. The relevant European international clearing system will, if the transaction meets its settlement requirements, deliver instructions to its depository to take action to effect final settlement on its behalf by delivering or receiving securities in DTC, and making or receiving payment in accordance with normal procedures for same day funds settlement applicable to DTC. Clearstream Banking participants or Euroclear participants may not deliver instructions directly to the depositories.

Initial Settlement

Interests in the Series 2024 Bonds will be in uncertified book-entry form. Purchasers electing to hold book-entry interests in the Series 2024 Bonds through Euroclear and Clearstream Banking accounts will follow the settlement procedures applicable to conventional Eurobonds. Book-entry interests in the Series 2024 Bonds will be credited to Euroclear and Clearstream Banking participants' securities clearance accounts on the business day following the date of delivery of the Series 2024 Bonds against payment (value as on the date of delivery of the Series 2024 Bonds). Direct Participants acting on behalf of purchasers electing to hold book-entry interests in the Series 2024 Bonds through DTC will follow the delivery practices applicable to securities eligible for DTC's Same Day Funds Settlement system. Direct Participants' securities accounts will be credited with book-entry interests in the Series 2024 Bonds following confirmation of receipt of payment to the Trustee on the date of delivery of the Series 2024 Bonds.

The Issuer will not impose any fees in respect of holding the Series 2024 Bonds; however, holders of book-entry interests in the Series 2024 Bonds may incur fees normally payable in respect of the maintenance and operation of accounts in the Clearing Systems.

Secondary Market Trading

Secondary market trades in the Series 2024 Bonds will be settled by transfer of title to book-entry interests in the Clearing Systems. Title to such book-entry interests will pass by registration of the transfer within the records of Euroclear, Clearstream Banking or DTC, as the case may be, in accordance with their respective procedures. Book-entry interests in the Series 2024 Bonds may be transferred within Euroclear and within Clearstream Banking and between Euroclear and Clearstream Banking in accordance with procedures established for these purposes by Euroclear and Clearstream Banking. Book-entry interests in the Series 2024 Bonds may be transferred within DTC in accordance with procedures established for this purpose by DTC. Transfer of book-entry interests in the Series 2024 Bonds between Euroclear or Clearstream Banking and DTC may be effected in accordance with procedures established for this purpose by Euroclear, Clearstream Banking and DTC.

General

None of Euroclear, Clearstream Banking or DTC is under any obligation to perform or continue to perform the procedures referred to above, and such procedures may be discontinued at any time.

Neither the Trustee nor any of their agents will have any responsibility for the performance by Euroclear, Clearstream Banking or DTC or their respective direct or indirect participants or account holders of their respective obligations under the rules and procedures governing their operations or the arrangements referred to above.

The information herein concerning Euroclear, Clearstream Banking, DTC and DTC's book-entry system has been obtained from sources that the Trustee believes to be reliable, but the Trustee takes no responsibility for the accuracy thereof.

Certificated Bonds

DTC may discontinue providing its services as depository with respect to the Series 2024 Bonds at any time by giving reasonable notice to the Issuer. Further, in the event that Bonneville determines that it is in the best interests of the beneficial owners of the Series 2024 Bonds that they be able to obtain bond certificates, the Issuer shall, upon the written instruction of Bonneville, so notify DTC, whereupon DTC shall notify the Participants of the availability through DTC of bond certificates. In either such event, the Series 2024 Bonds will be transferable in accordance with the Indenture.

APPENDIX F

VERIFIER'S REPORT

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Verifier's Report

Legal Name of Issuer:	**Port of Morrow, Oregon**
Issue Description:	Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9) Series 2024 (Federally Taxable) (Green Bonds - Climate Bond Certified)
Project:	Transmission System Improvements
Green Standards:	Climate Bonds Standard (Version 4.0) ICMA Green Bond Principles
Sector Criteria:	Electrical Grids and Storage
Keywords:	Transmission and distribution, electrification, hydropower, renewables, net zero, carbon-free, decarbonized grid, climate resilience, Pacific Northwest
Par:	$76,020,000
Evaluation Date:	May 8, 2024

CLIMATE BONDS DESIGNATION

The Port of Morrow, Oregon (the "Port") will issue Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9) Series 2024 (Federally Taxable) (Green Bonds - Climate Bond Certified) ("Series 2024 Bonds") to finance transmission system improvements to be leased and operated by Bonneville Power Administration ("Bonneville").

This Verifier's Report reflects Kestrel's view of Bonneville's projects and financing, allocation and oversight, and conformance of the Series 2024 Bonds with the Climate Bonds Standard (Version 4.0) and Certification Scheme, and *Electrical Grids and Storage* Sector Criteria. In our opinion, the Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9) Series 2024 (Federally Taxable) are impactful, net zero aligned, and conform with the internationally accepted Climate Bonds Standard (Version 4.0) and the *Electrical Grids and Storage* Sector Criteria (Version 1).

In recognition of the harmonization and alignment between the Climate Bonds Standard and the Green Bond Principles June 2021 (June 2022 Appendix I) established by the International Capital Market Association ("ICMA"), Kestrel has also evaluated and confirmed conformance of the Bonds with the Green Bond Principles.

ABOUT BONNEVILLE POWER ADMINISTRATION

Bonneville Power Administration ("Bonneville") was created in 1937 and is one of four regional federal power marketing agencies within the United States Department of Energy. The transmission system constructed, owned and operated by Bonneville includes over 15,000 miles of high voltage transmission lines and approximately 260 substations in Washington, Oregon, Idaho, Montana, Wyoming, and northern California.

In addition to providing transmission services, Bonneville markets power from federally-owned and non-federally-owned generation facilities, including 31 hydroelectric projects in the Pacific Northwest which are operated by the US Army Corps of Engineers ("Corps") or the US Bureau of Reclamation ("Reclamation"), and the Columbia Generating Station, a nuclear facility owned by Energy Northwest. Energy output in 2025 is expected to be over 9,600 MW under median water conditions and more than 7,900 MW under low water conditions. The electric power resources are primarily hydropower and power on the grid is nearly carbon-free. The hydroelectric projects operated by the Corps and Reclamation are managed for power generation, navigation, recreation, water supply, irrigation, and protection of fish and wildlife, among other purposes. Bonneville does not own or operate generation facilities but is responsible for selling power which makes up nearly 30% of power consumed in the region.

Power supply and transmission customers include publicly owned utilities, cooperatively owned utilities, tribal utilities, power generators, power marketers, and others. The service area is approximately 300,000 square miles and serves approximately 15 million people.

As a major marketer of low carbon energy and operator of the primary transmission network in the Pacific Northwest, Bonneville has multiple strategies to advance decarbonization goals. Supporting regional carbon reduction efforts is one of the primary objectives identified in the 2024-2028 Strategic Plan.

To meet decarbonization goals, Bonneville foresees that development of renewables will accelerate and these resources will require integration onto the transmission system. Approximately 1,055 MW of new wind and 849 MW of solar are expected to be added to Bonneville's balancing authority area by the end of Fiscal Year 2026. To meet these demands, Bonneville is pursuing a suite of projects through 2032 to minimize transmission congestion and enable connection of more renewable generation projects. These strategic projects are called the Evolving Grid Projects and are expected to increase transmission capacity by up to 6 GW systemwide.

Energy conservation is also considered in resource planning. The Energy Efficiency Action Plan outlines how Bonneville can strengthen efforts to increase energy efficiency and energy conservation to reduce load requirements. Strategies address efficiency opportunities in distribution systems, demand-response, and residential, commercial, industrial, agriculture, and federal sectors.[1]

In addition to maintaining and expanding access to low carbon energy, Bonneville has taken a proactive approach to climate resilience. The Climate Vulnerability Assessment and Resilience Plan developed in 2022 is a comprehensive assessment of potential climate risks to the system and strategies to mitigate

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1 "Energy Efficiency Action Plan 2022-2027," Bonneville Power Administration, https://www.bpa.gov/-/media/Aep/energy-efficiency/document-library/bpa-2022-2027-ee-action-plan.pdf.

those risks. Additionally, the first Wildfire Mitigation Plan for the transmission system was released in 2020.[2]

CONFORMANCE WITH CLIMATE BONDS STANDARD AND SECTOR CRITERIA

Bonneville and the Port engaged Kestrel to provide an independent verification on alignment of the Series 2024 Bonds with the Climate Bonds Standard (Version 4.0) and Certification Scheme ("Climate Bonds Standard"), and the *Electrical Grids and Storage* Sector Criteria. The Climate Bonds Initiative ("Climate Bonds") administers the Standard and Sector Criteria. Additionally, Kestrel examined alignment of the Series 2024 Bonds with the United Nations Sustainable Development Goals ("UN SDGs").

Kestrel is a Climate Bonds Initiative Approved Verifier. The Kestrel Verification Team included environmental scientists and financial professionals. We performed a Reasonable Assurance engagement to independently verify that the bonds meet relevant criteria, in all material respects.

For this engagement, Kestrel reviewed Bonneville and the Port's bond disclosure documentation, internal Green Bond Framework, disclosures and documentation on the allocation and uses of bond proceeds, as well as relevant plans and alignment to Bonneville's overarching climate objectives. We examined public and non-public information and interviewed members of Bonneville. Our goal was to understand the planned use of proceeds, procedures for managing proceeds, and plans and practices for reporting in sufficient detail to verify the bonds.

Relevant Climate Bonds Sector Criteria and Other Standards

The Series 2024 Bonds align with the Climate Bonds Standard (Version 4.0) and *Electrical Grids and Storage* Criteria (Version 1).

Assurance Approach

Kestrel's responsibility was to conduct a Reasonable Assurance engagement to determine whether the Series 2024 Bonds meet, in all material respects, the requirements of the Climate Bonds Standard. Our Reasonable Assurance was conducted in accordance with the Climate Bonds Standard (Version 4.0) and the *International Standard on Assurance Engagements (ISAE) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information*. Information relating to this engagement and the Verifier's and Issuer's Responsibilities, and Independence and Quality Control are available in Appendix D.

Kestrel has relied on information provided by Bonneville. There are inherent limitations in performing our assurance; fraud, error or non-compliance may occur and not be detected. Kestrel is not responsible or liable for any opinions, findings or conclusions within the information provided by Bonneville that are incorrect. Our assurance is limited to the review of Bonneville's policies and procedures that are, in Kestrel's view, relevant to the key components of the Climate Bonds Standard (Version 4.0). The distribution and use of this verification report are at the sole discretion of Bonneville. Kestrel does not accept or assume any responsibility for distribution to any other person or organization.

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[2] "Wildfire Mitigation," Bonneville Power Administration, accessed April 24, 2024, https://www.bpa.gov/energy-and-services/transmission/wildfire-mitigation.

Use of Proceeds

The Series 2024 Bonds finance improvements to the Bonneville transmission system (the "Project") to enable the transition to a carbon-free grid and accommodate increased demand for clean power. The projects improve reliability of the major regional transmission system in the Pacific Northwest and support decarbonization of the electrical grid.

Electrification of vehicles and buildings and addition of intermittent renewables to the resource mix create new demands on transmission and distribution infrastructure. Upgrades to this infrastructure are vital to the transition to a carbon-free grid by 2030. According to the National Renewable Energy Laboratory, transmission capacity needs nationwide are between two and three times the capacity installed in 2022 and require between 1,400 and 10,100 miles of new high-capacity lines per year. Investment needed for the entire US power system is estimated at $330 billion to $740 billion, a significant portion of which is transmission and distribution infrastructure.[3] To achieve targeted US emission reductions, transmission capacity should expand approximately 50% faster than recent rates.[4]

Transmission system improvements financed by the Series 2024 Bonds are designed to maintain a reliable grid and accommodate new large-scale renewable generation developments. It is also designed for major shifts in demand expected as a result of large-scale electrification that is also necessary to meet emission reduction targets. Projects are all completed as of April 2022 and are described in Table 1.

Table 1. Projects to be financed with the Series 2024 Bonds

Project	Description
Keeler Substation Static Var Compensator Upgrade	Addition of static voltage controls at the Keeler substation located west of Portland, Oregon; stabilizes system voltage and eliminates wasted electricity
Maple Valley Substation Static Var Compensator Upgrade	Addition of static voltage controls at Maple Valley substation located southeast of Seattle, Washington; stabilizes system voltage and eliminates power loss
Ross Complex Facility	Construction of a maintenance facility for equipment and fleets which are wholly dedicated to the eligible system; electric vehicle chargers are expected to be added in the future
Slatt Substation Spare Transformer	Addition of a spare transformer to the Slatt Substation in Oregon to minimize system outages and improve system resilience
Fossil Substation Power Transformers	Replacement of power transformers at the Fossil Substation in north central Oregon to improve system reliability and reduce PCB contamination from existing transformers[5]

[3] Paul Denholm et al., "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," National Renewable Energy Laboratory, 2022, https://www.nrel.gov/docs/fy22osti/81644.pdf.

[4] "Climate Progress and the 117th Congress: The Impacts of the Inflation Reduction Act and Infrastructure Investment and Jobs Act," Rapid Energy Policy Evaluation and Analysis Toolkit (REPEAT), Princeton, July 2023, https://repeatproject.org/docs/REPEAT_Climate_Progress_and_the_117th_Congress.pdf.

[5] Polychlorinated Biphenyl (PCB) was historically used in certain electrical equipment. PCBs tend to break down very slowly in the environment and can be toxic to humans and wildlife with exposure at relatively low concentrations. Transformers and other equipment manufactured in the US after 1979 does not contain PCBs.

Net Zero Alignment
As the main grid operator in the Pacific Northwest, the Bonneville projects are paramount to achieving net zero greenhouse gas emissions in the region. Clean energy targets have increased demand for interconnections and transmission services for renewable energy. The State of Washington has set a goal to reach 100% clean electricity by 2035 and the State of Oregon set a goal to reduce greenhouse gas emissions by 100% below a baseline by 2040. The US national target is to reach net zero greenhouse gas emissions by 2050.

The financed projects support addition of interconnections and expand capacity to meet changing demands as a result of these ambitious grid decarbonization targets and interconnection requests. Rapid development of transmission infrastructure is necessary to accommodate increased renewables and electrification of buildings and transportation. Electricity production is the second highest source of greenhouse gas emissions in the US.[6] Providing renewable and carbon-free energy through a reliable and resilient transmission system is critical to reducing these emissions.

Sector Criteria for Electrical Grids and Storage (Version 1.0)
As per the *Electrical Grids and Storage* Sector Criteria, bonds must meet both Mitigation and Adaptation & Resilience Criteria to demonstrate conformance.

Mitigation Criteria: The average grid emissions factor in which the infrastructure is located is below 100 g CO_2e/kWh. Alternatively, more than 67% of new generation capacity in the system is expected to have emissions intensities below 100 g CO_2e/kWh over a rolling five-year period.

The Bonds only finance improvements to transmission infrastructure in the Bonneville system. The Bonneville system primarily transmits carbon-free energy and continues to integrate new renewable generation resources to the system. The grid emissions factor is 16 g CO_2e/kWh and thus, the transmission infrastructure projects meet the Mitigation criteria.

Bonneville has significant plans and procedures in place to meet criteria in the Adaptation & Resilience checklist included in Appendix C. The weighted average operational lifetime of the financed assets exceeds the term of the Series 2024 Bonds.

ICMA Green Bond Principles
The bond-financed activities are eligible projects as defined by the Green Bond Principles in the *Renewable Energy* project category.

Process for Project Evaluation and Selection

Bonneville Capital Programs and projects financed by the Series 2024 Bonds are developed based on multi-year strategic plans, the annual Transmission Plan, an asset management system and regional coordination among grid operators.

[6] "Sources of Greenhouse Gas Emissions: Electricity," United Stated Environmental Protection Agency, accessed May 3, 2024, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#electricity.

The 2024-2028 Strategic Plan sets out goals for the next five years to prepare for transformation of electrical grids, increase reliability and resilience, and accommodate changing customer needs. The grid modernizations financed by the Series 2024 Bonds advance multiple objectives in the Strategic Plan, including *Support regional carbon reduction efforts*; *Advance transmission investments and innovative solutions to integrate loads and resources*; and *Promote energy efficiency investments to meet the long-term resource needs of Bonneville, our customers and the region*.

The annual Transmission Plan describes capital priorities for the transmission system to serve expected loads and load growth. The most recent 2023 Transmission Plan[7] describes necessary projects to meet transmission service requests, interconnection requests, upgrades to serve new load growth, and improvements to reliability. This planning process informed prioritization of projects financed by the Series 2024 Bonds.

Physical assets are monitored through the Asset Management Key Strategic Initiative and related strategic asset management plans and asset plans. Each of these informs priorities for investment through the Capital Program. Priorities in the Climate Vulnerability Assessment and Resilience Plan and the Wildfire Mitigation Plan ensure projects are constructed to be resilient to physical climate risks.

Bonneville also participates in large, coordinated regional planning efforts to provide effective and reliable grid operations and to prioritize transmission infrastructure projects for financing. Examples of these regional efforts include NorthernGrid, a regional transmission planning organization with 13 member utilities, and the Western Transmission Expansion Coalition which coordinates inter-regional transmission planning.

Management of Proceeds

The Series 2024 Bonds refinance debt which financed construction and improvement of transmission infrastructure and pay costs of issuance. The Project was originally financed through a note purchase agreement which will be refinanced with proceeds of the Series 2024 Bonds. Proceeds will be used immediately at closing to repay the outstanding debt and will not be held in temporary investments prior to spending.

Reporting

Bonneville has several ongoing reporting processes that provide investors with insights into operations and activities.

- Annual reports include updates on key indicators related to operational and financial performance and are available at: bpa.gov/about/finance/annual-reports.
- Reports on progress toward energy conservation targets are released separately from the comprehensive annual reporting efforts: bpa.gov/energy-and-services/efficiency/energy-conservation-annual-review.

[7] "Transmission Plan: Open Access Transmission Tariff Attachment K Planning Process," Bonneville Power Administration, December 2023, https://www.bpa.gov/-/media/Aep/transmission/attachment-k/2023-bpa-transmission-plan.pdf.

- Bonneville also reports progress on capital plans in Quarterly Business Reviews: bpa.gov/about/finance/quarterly-business-review.
- Systemwide sustainability metrics are reported on the Bonneville website: bpa.gov/environmental-initiatives/sustainability/metrics.
- Bonneville reports annually on greenhouse gas emissions through The Climate Registry voluntary reporting program: theclimateregistry.org/members/bonneville-power-administration/.

In accordance with the Climate Bonds Standard, Kestrel will be engaged to provide one Post-Issuance Report within 24 months of issuance to confirm continued conformance of the Series 2024 Bonds with the relevant Standards and Criteria.

Bonneville will also submit continuing financial disclosures to the Municipal Securities Rulemaking Board ("MSRB") as long as the Series 2024 Bonds are outstanding, as well as reports in the event of material developments. This reporting will be done annually on the Electronic Municipal Market Access ("EMMA") system operated by the MSRB.

ALIGNMENT WITH UN SDGs

The Series 2024 Bonds support and advance the vision of the United Nations Sustainable Development Goals ("UN SDGs"), including:

Affordable and Clean Energy (Targets 7.1, 7.2)
Capital investments to improve reliability of a system delivering clean and renewable energy to customers

Industry, Innovation and Infrastructure (Targets 9.1, 9.4)
Installation of infrastructure to increase flexibility of the grid in alignment with large-scale electrification, deployment of renewables and wildfire resilience

Sustainable Cities and Communities (Target 11.6)
Comprehensive upgrades to grid infrastructure upgrades to maintain service reliability with electrification of buildings and vehicles

Climate Action (Target 13.2)
Continued implementation of projects to reach long-term grid decarbonization targets while maintaining grid reliability

Full text of the Targets for these Goals is available in Appendix A, with additional information available on the United Nations website: un.org/sustainabledevelopment

ASSURANCE STATEMENT AND CONCLUSIONS

Based on the Reasonable Assurance procedures we have conducted, in our opinion, the Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 9) Series 2024 (Federally Taxable) are impactful, net zero aligned, and conform, in all material respects, with the current Climate Bonds Standard, and the bond-financed activities are completely aligned with the *Electrical Grids and Storage* Sector Criteria. The Projects provides critical infrastructure to meet ambitious grid decarbonization targets.

Sincerely,

April Strid

April Strid, Lead Verifier
Kestrel
Hood River, Oregon, United States
May 8, 2024

About

Kestrel Sustainability Intelligence™ for municipal markets helps set the market standard for sustainable finance. We do this through verification and our comprehensive Analysis and Scores.

Kestrel is a leading provider of external reviews for green, social and sustainability bond transactions. We are qualified to evaluate corporate and municipal bonds in all asset classes worldwide for conformance with international green and social bond standards.

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- Cailey Martin - Senior ESG Analyst

Disclaimer

This Opinion aims to explain how and why the discussed financing meets the Climate Bonds Standard based on the information that was provided by Bonneville or made publicly available by Bonneville and relied upon by Kestrel only during the time of this engagement (April – May 2024), and only for purposes of providing this Opinion.

We have relied on information obtained from sources believed to be reliable, and assumed the information to be accurate and complete. However, Kestrel can make no warranty, express or implied, nor can we guarantee the accuracy, comprehensive nature, merchantability, or fitness for a particular purpose of the information we were provided or obtained.

By providing this Opinion, Kestrel is neither addressing nor certifying the credit risk, liquidity risk, market value risk or price volatility of the projects financed by the Climate Bonds. It was beyond Kestrel's scope of work to review for regulatory compliance, and no surveys or site visits were conducted by us. Furthermore, we are not responsible for surveillance, monitoring, or implementation of the project, or use of proceeds.

The Opinion delivered by Kestrel is for informational purposes only, is current as of the date of issuance, and does not address financial performance of the Climate Bonds or the effectiveness of allocation of its proceeds. This Opinion does not make any assessment of the creditworthiness of Bonneville, nor its ability to pay principal and interest when due. This Opinion does not address the suitability of a Bond as an investment, and contains no offer, solicitation, endorsement of the Bonds nor any recommendation to buy, sell or hold the Bonds. Kestrel accepts no liability for direct, indirect, special, punitive, consequential or any other damages (including lost profits), for any consequences when third parties use this Opinion either to make investment decisions or to undertake any other business transactions.

This Opinion may not be altered without the written consent of Kestrel. Kestrel reserves the right to revoke or withdraw this Opinion at any time. Kestrel certifies that there is no affiliation, involvement, financial or non-financial interest in Bonneville or the projects discussed. We are 100% independent. Language in the offering disclosure supersedes any language included in this Opinion.

Use of the United Nations Sustainable Development Goal (SDG) logo and icons does not imply United Nations endorsement of the products, services, or bond-financed activities. The logo and icons are not being used for promotion or financial gain. Rather, use of the logo and icons is primarily illustrative, to communicate SDG-related activities.

Appendix A.
UN SDG TARGET DEFINITIONS

Target 7.1
By 2030, ensure universal access to affordable, reliable and modern energy services

Target 7.2
By 2030, increase the share of renewable energy in the global energy mix

Target 9.1
Develop quality, reliable, sustainable and resilient infrastructure, including regional and transborder infrastructure, to support economic development and human well-being, with a focus on affordable and equitable access for all

Target 9.4
By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes, with all countries taking action in accordance with their respective capabilities

Target 11.6
By 2030, reduce the adverse per capita environmental impact of cities, including paying special attention to air quality and municipal and other waste management

Target 13.2
Integrate climate change measures into national policies, strategies and planning

Appendix B.
ADAPTATION & RESILIENCE CHECKLIST

Adaptation and Resilience Checklist for Grid and Storage Infrastructure (Tables B.1–B.5)

Table B.1. Clear boundaries and critical interdependencies between the infrastructure and the system it operates within are identified.

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
1.1	Boundaries of the infrastructure are defined using (1) a listing of all infrastructure and assets and activities associated with the use of the bond proceeds, (2) a map of their location, and (3) identification of the expected operational life of the activity, asset or project.	A detailed budget and list of all infrastructure, assets, and activities associated with the Series 2024 Bond proceeds has been provided. The service territory and locations of the financed assets are defined. The average operational life of the assets exceeds the term of the Series 2024 Bonds.
1.2	Critical interdependencies between the infrastructure and the system within which it operates are identified. Identification of these interdependencies should consider the potential for adverse impacts arising from, but not limited to: (1) the effects of supply disruption or interruption on dependent electricity users or populations; (2) exacerbation of wildfires; (3) relationships of the asset/project to nearby flood zones; (4) reduction in pollinating insects and birds; (5) reduction in biodiversity or High Conservation Value[10] habitat; (6) damage or reduction in value of neighboring property due to boundary structures at risk of falling during storm events; (7) fire and other practices that affect air quality; (8) appropriation of land or economic assets from nearby vulnerable groups[11] [10] High Conservation Value (HCV) habitat criteria in accordance with https://www.hcvnetwork.org [11] According to IFC Performance Standards	Interdependencies and potential impacts from factors listed in criteria 1.2 are identified. Supply disruption, exacerbation of wildfires, flooding, and fire and other practices that affect air quality are addressed in the Vulnerability Assessment and Resilience Plan ("VARP"). Exacerbation of wildfires and other practices that affect air quality are addressed further in Wildfire Mitigation Plans. Bonneville has ongoing involvement in US Department of Energy studies assessing the impacts of climate change on federal power marketing administrations.

Table B.2. An assessment has been undertaken to identify the key physical climate hazards to which the infrastructure will be exposed and vulnerable to over its operating life.

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
2.1	Key physical climate risks and indicators of these risks are identified in line with the following guidelines. Risks are identified based on (a) a range of climate hazards, and (b) information about risks in the current local context, including reference to any previously identified relevant hazard zones, e.g., flood zones. In order to be confident that assets and activities are robust and flexible in the face of climate change uncertainties, it is essential that the climate risks being assessed and addressed cover those that are of greatest relevance to T&D grids and electrical energy storage. The physical characteristics of climate change that must be considered in the risk assessment include: • Temperature rise o High temperatures can impact the electrical rating of assets, reducing transmission capacity and potentially reducing the ability of the network to meet demand. o Increasing temperatures can also result in extension of overhead lines, which reduces the clearance above trees. o Increased temperatures may also result in changes to the load on assets, due to increased cooling demands (higher summer peak demands) and less winter heating (reduced winter peak). • Increased heavy rainfall o Heavy rainfall can result in flash pluvial flooding, which could significantly impact electrical assets, particularly ground mounted assets. • Sea-level rises o Potential for flooding of coastal infrastructure and assets at risk from storm surge events. • Increased lightning o Lightning strikes have potential to cause transient outages due to power surges. • Increased winds / gales o Strong winds can cause damage to overhead transmission and distribution lines and supporting infrastructure (pylons and poles). o Up-rooting of trees and vegetation can also have an impact on power lines. • Increased snow, sleet, ice, freezing fog o Ice and snow accretion can make overhead power lines vulnerable to high-winds o Snow and ice can also impede access to sites for repairs in the event of a fault. • Increased coastal / river erosion o Risk to assets in coastal or riverbank locations • Wildfires o Wildfires present a risk to electricity infrastructure in affected areas and can significantly inhibit access to repair damaged infrastructure. o Electricity infrastructure can also be a cause of wildfires. For example, contact between transmission lines and dry vegetation has potential to start fires. • Landslides / ground movement o Potential to risk to both underground and above ground infrastructure from ground movement. o Potential for access to be impeded for repairs.	Key physical climate risks and indicators of these risks are identified in the VARP. Key risks considered in the VARP include: • More frequent, longer and more intense heat waves • Move frequent, severe wildfires and a longer fire season • Increased coastal flooding due to sea-level rise • More frequent and intense inland flooding • More extreme heavy-rainfall events • More landslides Erosion is also discussed in the VARP in the context of the risks above. The VARP project team collaborated with Bonneville meteorologists and climate change specialists to determine the climate hazards likely to impact the Pacific Northwest over the coming years. State-specific and regional literature developed by the National Oceanic and Atmospheric Administration, the River Management Joint Operating Committee (which has membership from Bonneville, the US Army Corps of Engineers, and the Bureau of Reclamation), and the US Global Change Research Program also informed the VARP. Bonneville has been monitoring climate-related risks to its operations for nearly two decades and developed its first Climate Change Adaptation Plan in 2012. Bonneville coordinates with other utilities in and around its service territory to provide essential materials to ensure grid reliability in the event of an emergency. Bonneville also negotiates agreements with land management agencies to coordinate actions occurring near power lines. A 2017

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
	Issuers might consider the climate risks posed through specific interdependencies which might include, for example: • Availability of telecommunications for control systems and operational / field staff communications when dealing with extreme weather events, where the telecommunications rely on third party providers and infrastructure. • Flood risk and resilience will likely have interdependencies with local and national agencies, for example related to local flood defenses, coastal flood risk management, shoreline management plans etc. Optional guidance for carrying out risk assessments: • Users should apply climate scenarios based on representative concentration pathway (RCP) 4.5 and 8.5 or similar / equivalent to ensure consideration for worst case scenario. • A broad range of models can be used to generate climate scenarios. • Time horizons for assessing climate risk in agriculture can be based on annual seasonal forecasts and every ten years for the lifetime of the assets and projects. Where accurate assessments of climate variability for specific locations are not possible, use worst-case scenarios. • Risks can be characterized by the associated annual probability of failure or annual costs of loss or damage. • For risk assessment, the TCFD The Use of Scenario Analysis in Disclosure of Climate-Related Risks and Opportunities is recommended.	Memorandum of Understanding with the US Forest Service requires advance coordination on maintenance activities and includes a fire prevention and suppression plan designed to prevent and minimize wildfire. The VARP outlines system-specific likelihood and consequence scales to identify the impact that climate hazard events have on critical systems (facilities, fleet, supply chain, transmission, and workforce). Subsequent VARP analysis cycles will expand in scope to include additional systems and will respond to any future developments in climate modeling for the region.

Table B.3. The measures that have or will be taken to address those risks, mitigate them to a level such that the infrastructure is suitable to climate change conditions over its operational life.

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
3.1	The following are examples of risk management activities that bond issuers might consider, or that might be adopted as part of regulations (e.g. codes and standards). This list is not exhaustive and bond issuers should fully assess the mitigation measures that are relevant to the climate risks and impacts identified in the risk assessment. Temperature - Design standards that maintain equipment rating over its lifetime performance in the face of all potential ranges of temperature rise - Manage vegetation under power lines to ensure adequate clearance is maintained - Assess changing demand profile (milder winters, increased summer cooling) over equipment lifetime Rainfall: - Design for resilience to pluvial flooding - Assessment of site drainage requirements - Impact of restricted access to sites / lines due to flooding Increased lightning - Design of electrical equipment to withstand lightning impulses, including shielding and surge suppression devices - Redundancy Increased winds / gales - Design to withstand extreme winds - Cut vegetation regularly to safe distance to reduce risk from up-rooting - Invest in storm and hurricane forecasting tools - Consider placing cables underground - Redundancy Increased snow, sleet, ice, freezing fog - Design equipment for ice loading - Suitable vehicles for access to sites in heavy snow / icy conditions Increased flooding - Flood risk assessment and planning - Site ground installations outside of potentially affected zones - Ensure flood defense systems and coastal management plans are adequate - Consideration of site access during flooding events Increased coastal / river erosion - Shoreline management plans / coastal erosion assessment Wildfires - Management of vegetation around electricity infrastructure to ensure adequate clearance Landslides / ground movement - The potential for ground movement and landslides should be taken into account when assessing sites for installing grid infrastructure.	Completed or ongoing risk management activities include, but are not limited to: • Build new facilities with HVAC systems that have extended temperature ranges and cooling/heating duration above climate forecasts • Implement enhanced inspection and operations and maintenance program for stormwater systems and roads • Re-evaluate replacement schedule and replace fleet assets with equipment that requires less downtime and maintenance • Purchase additional stocks of air, cabin and miscellaneous filters for areas determined to be at high risk of wildfires • Implement a capital asset management software program to optimize fleet size and placement • Assess material availability vulnerabilities to ensure field inventories reflect unique regional system needs • Coordinate with other utilities in and around the BPA service territory to provide essential materials to ensure grid reliability in the event of an emergency • Maintain a full staff of technical experts and have succession plans in place to foster an environment of proactive and creative solutions to material access issues • Ensure project schedules are able to account for shipping delays for materials with long lead times • Develop relationships with suppliers and contracting mechanisms to ensure material availability • Continue to implement a comprehensive vegetation management program to minimize vegetation-related fire hazards on BPA rights-of-way, easements and fee-owned land • Continue to conduct regular inspections of transmission assets and perform maintenance • Apply fire-resistant coating to wood poles in areas vulnerable to wildfires • Develop and execute business and continuity plans for emergency operations • Negotiate agreements with land management agencies to coordinate actions occurring near power lines

<table>
<tr><th>No.</th><th>Adaptation and resilience checklist for grid and storage infrastructure</th><th>Submitted</th></tr>
<tr><td></td><td>General risk mitigation measures:
- Business continuity plans
- System restoration plans
- Black start
- Islanded operation / microgrids
- System security standards</td><td>• Install barriers to protect tower legs from flood debris impact
• Relocate towers away from riverbanks
• Install towers on flood control foundations or add additional weight to towers to prevent uplift
• Relocate towers away from landslide area
• Replace four-legged lattice towers with single tubular poles to reduce differential leg movement
• Survey known and potential slide areas to track movement of transmission facilities
Bonneville has a Continuity of Operations program, an Outage Coordination Policy, a Wildfire Mitigation Plan, and a Blackstart Coordination Process.
Risk management activities that are actively being planned include, but are not limited to:
• Implement a Material Visibility Initiative to assess what materials are deemed critical and in what quantities they should be held in stock to respond to event-driven demand
• Develop a demand planning tool and dashboard to assess and communicate appropriate levels of materials in emergency management stock
• Design and construct transmission assets to reduce ignition sources
• Replace wood poles with steel poles in areas vulnerable to wildfires
• Upgrade older buildings in areas vulnerable to wildfires with fire-resistive materials</td></tr>
<tr><td>3.2</td><td>Risk reduction measures must be tolerant to a range of climate hazards and not lock-in conditions that could result in maladaptation.</td><td>The 2022 VARP focuses on climate hazards expected over a 20-year timeframe, from 2022 to 2042. The status of resilience measures is reviewed and updated as needed each year, and Bonneville will refresh the VARP every four years. As Bonneville plans for and develops its second VARP assessment, Bonneville intends to refine its methodology, particularly around the measurement of risk, and harmonize this assessment with other ongoing resilience planning efforts. Bonneville will also respond to any future developments in climate modeling for the region in subsequent VARP analysis cycles. Long-term planning periods, annual updates on resilience measures, and regular refresh of the VARP to be responsive to future developments avoid lock-in conditions.</td></tr>
</table>

Table B.4. The infrastructure enhances the climate resilience of the defined system it operates within, as indicated by the boundaries of and critical interdependencies with that system as identified in item 1 in this checklist.

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
4.1	Issuers are to assess the climate resilience benefits of system focused assets and activities and demonstrate they are 'fit for purpose', in the sense that they enhance climate resilience at a systemic level, with the flexibility to take into account the uncertainty around future climate change impacts. The assessment is conducted according to the principle of best available evidence during the investment period taking into account the infrastructure's boundaries and critical interdependencies as defined in Criteria 1. 'Fit for purpose' is defined as measures that mitigate the following effects: (1) the effects of supply disruption or interruption on dependent electricity users or populations; (2) exacerbation of wildfires; (3) relationships of the asset/project to nearby flood zones; (4) reduction in pollinating insects and birds; (5) reduction in biodiversity or High Conservation Value[12] habitat; (6) damage or reduction in value of neighboring property due to boundary structures at risk of falling during storm events; (7) fire and other practices that affect air quality; (8) appropriation of land or economic assets from nearby vulnerable groups[13]; [12] High Conservation Value (HCV) habitat criteria in accordance with https://www.hcvnetwork.org. [13] According to IFC Performance Standards	Financed improvements to the four substations enhance climate resilience at a systemic level by improving system reliability. Static var compensators at the Maple Valley and Keeler substations serve to stabilize voltage, improve system efficiency, and reduce power losses. The spare transformer at the Slatt substation provides an additional unit for system reliability when maintenance is performed on other units or when outages occur. Financed construction of the Ross Fleet Services Building includes pollinator-friendly landscaping and on-site stormwater treatment. The new service shop reduces vehicle repositioning with 10 pass-through bays, allowing equipment to be redeployed to the field more quickly. The Building is seismically resilient with an operations center design that supports resilient disaster response and continuous functioning. Multiple system-level initiatives and infrastructure upgrades, including those listed in Criteria 3, enhance reliability and resilience of the system.

Table B.5. The issuance is required to demonstrate that there will be ongoing monitoring and evaluation of the relevance of the risks and resilience measures and related adjustments to those measures will be taken as needed.

No.	Adaptation and resilience checklist for grid and storage infrastructure	Submitted
5.1	Indicators for risks identified under item 2 in this checklist are provided.	Bonneville is required to comply with standards set by the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC). Not meeting reliability standards is one of the primary indicators of key climate hazards. As Bonneville plans for and develops its second VARP assessment, Bonneville intends to refine its methodology, particularly around the measurement of risk, and harmonize this assessment with other ongoing resilience planning efforts. The VARP outlines system-specific likelihood and consequence scales to identify the impact that climate hazard events have on critical systems (facilities, fleet, supply chain, transmission, and workforce). Subsequent VARP analysis cycles will expand in scope to include additional systems and will respond to any future developments in climate modeling for the region.
5.2	Indicators for risk mitigation measures identified under item 3 in this checklist are provided.	The 2022 VARP focuses on climate hazards expected over a 20-year timeframe, from 2022 to 2042. The status of resilience/risk mitigation measures is reviewed, and updated as needed, each year, and Bonneville will refresh the VARP every four years.
5.3	Indicators for “fit for purpose” resilience benefit measures identified under item 4 in this checklist are provided.	Indicators and the need for modification of “fit for purpose” resilience measures are identified through annual capital and resource planning and operational performance.
5.4	Issuers have a viable plan to annually monitor (a) climate risks linked to the infrastructure, (b) climate resilience performance, (c) appropriateness of climate resilience measure(s) and to adjust as necessary to address evolving climate risks.	The VARP, Strategic Asset Management Plans, and annual capital and resource planning amount to comprehensive plans to annually monitor climate risks linked to the infrastructure, climate resilience performance, and appropriateness of climate resilience measures. Regular updates ensure that Bonneville can adjust as necessary to address evolving climate risks.
5.5	Where electricity supply has been interrupted, the number of customer interruptions and customer minutes lost (i.e. aggregate duration of supply interruptions) should be measured and reported, together with the cause of the interruption. Any actions taken to reduce the risk of further impacts should also be recorded.	Bonneville provides online reporting of customer service interruptions, transmission line interruptions, and transformer interruptions. Reports include outage durations, causes, and the responsible parties.

Appendix C.

ASSURANCE PROCEDURES FOR USE OF PROCEEDS VERIFICATION (CLIMATE BONDS STANDARD V4.0)

REQUIREMENT		ASSURANCE PROCEDURES PERFORMED BY KESTREL
2.1. Utilization of Proceeds		
2.1.1.	**Project Documentation**	Review documentation of the Nominated Projects assessed as likely to be Eligible Projects, and list of Nominated Projects that Issuer will keep up-to-date during the term of the bond.
2.1.2.	**Valuation**	Review net proceeds of the bond to ensure they are not greater than the value of the project.
2.1.3.	**Multiple Nominations for Certified Debt Instruments**	Review Nominated Projects or distinct portions of the Nominated Projects for previous nominations to other Certified Climate Debt Instruments, green bonds, or other designated instruments. Review and confirm whether Nominated Projects have been refinanced by other Certified Debt Instruments or bonds under assessment will refinance existing Certified Debt Instruments.
2.2. Process for Evaluation and Selection of Projects and Assets		
2.2.1.	**Process**	Review documentation of the process the Issuer followed to identify projects and confirm eligibility requirements for inclusion of Nominated Projects in the bond. Review planning documents which establish goals, priorities and potential impact.
2.2.2.	**Environmental Statement, Eligibility & Technical Criteria (i.-vi.)**	Review additional documentation Issuer provided on further aspects of identification process including strategic directions and standards. Review the Issuer's environmental and social integrity policy, exclusion criteria, and/or Green Bond Framework, and confirm its coverage of the Nominated Projects. Review statement of the climate-related objectives of the bond. Test Nominated Projects to determine whether they meet the minimum technical requirements of the Climate Bonds Standard and relevant Sector Criteria.
2.3. Management of Proceeds		
2.3.1.	**Documentation of Processes & Procedures**	Confirm that policies, processes and procedures for tracking financial flows of bond proceeds to the Nominated Projects are in place.
a.	**Tracking of Proceeds**	Review allocation of funds to ensure they can be tracked against Nominated Projects.
b.	**Managing of Unallocated Proceeds**	Review documentation for the management of bond proceeds for funds prior to allocation to a Nominated Project and review eligible temporary investments for unallocated proceeds.
c.	**Earmarking Funds**	Confirm policies, processes and procedures to identify flows of proceeds related to the Bond have been established.
2.3.2.	**Ring-Fenced Funds**	Where proceeds will be ring-fenced, confirm processes and procedures to allocate funds to accounts, and track and monitor payments from the relevant accounts.
2.4. Pre-Issuance Reporting: Green Finance Framework and Disclosure Documentation		
2.4.1	**Bond Disclosure Documentation**	Review Issuer's Green Bond Framework and confirm plans to make the document publicly available and provide it to the Climate Bonds Standard Secretariat. Confirm inclusion of necessary information within the Green Bond Framework.
2.4.2. i.	**Confirmation of Alignment**	In the Green Bond Framework, confirm documentation and review areas of investment align with the Climate Bonds Standard and review statements of alignment with other relevant standards.
ii.	**Uses of Proceeds**	In the Green Bond Framework, confirm documentation and review expected uses of proceeds and amounts allocated to activities in relevant sectors and subsectors.

REQUIREMENT		ASSURANCE PROCEDURES PERFORMED BY KESTREL
2.4. Pre-Issuance Reporting: Green Finance Framework and Disclosure Documentation *(continued)*		
iii.	**Decision-making Process**	In the Green Bond Framework, confirm documentation of decision-making processes and positioning in the context of the Issuer's overarching objectives.
iv.	**Management of Proceeds**	In the Green Bond Framework, confirm documentation and review processes for managing proceeds.
v.	**Reporting and External Review**	In the Green Bond Framework, confirm documentation and review processes for reporting and engagement of an Approved Verifier.
2.4.3. i.	**Sector Criteria Assumptions and Methodologies**	In the Green Bond Framework, confirm documentation of assumptions and methodologies to evaluate conformance with Sector Criteria.
ii.	**Temporary Investment Instruments**	In the Green Bond Framework, confirm documentation of allowable temporary investment instruments.
iii.	**Reporting Approach**	In the Green Bond Framework, confirm disclosure of intended approach to providing Update Reports and/or undertaking periodic Assurance Engagements during term of bond to reaffirm conformance with the Climate Bonds Standard.
iv.	**List of Nominated Projects**	In the Green Bond Framework, confirm disclosure of list of Nominated Projects likely to be eligible.
v.	**Refinancing**	In the Green Bond Framework, confirm disclosure of proportion of proceeds for refinancing, if applicable.
2.4.4.	**Transparency**	Confirm disclosure is comprehensive and as detailed as possible, given any Issuer or project-specific limitations such as confidentiality.
2.4.5.	**Disclosure Documentation**	Confirm incorporation of key information in Disclosure Documentation.
i.	**Sector Criteria Disclosure**	Confirm "investment areas," or alignment with the Climate Bonds Taxonomy and relevant Sector Criteria for Nominated Projects.
ii.	**Temporary Investments**	Confirm disclosure of eligible temporary investments for unallocated proceeds.
iii.	**Verifier**	Confirm disclosure of Verifier selected for Pre-Issuance and Post-Issuance Engagements.
iv.	**Ongoing Reporting**	Confirm disclosure of intended ongoing reporting on the Nominated Projects and allocation of proceeds.
v.	**CBI Disclaimer**	Confirm incorporation of the CBI Disclaimer as provided in the Certification Agreement.

Appendix D.
VERIFIER'S & ISSUER'S RESPONSIBILITIES

Verifier's Responsibilities

Kestrel's responsibilities for confirming alignment of the Series 2024 Bonds with the Climate Bonds Standard and *Electrical Grids and Storage* Criteria include:

- Assess the uses of proceeds for conformance with relevant Standard and Criteria;
- Assess and certify Bonneville's internal processes and controls, including selection process for projects and assets, internal tracking of proceeds, and the allocation system for funds;
- Assess policies and procedures established by Bonneville for reporting;
- Assess the readiness of Bonneville to meet the Climate Bonds Standard (Version 4.0) and *Electrical Grids and Storage* Sector Criteria; and
- Express a Reasonable Assurance conclusion.

Issuer's Responsibilities

Issuer was responsible for providing detailed information and documents relating to:

- The details of the Nominated Projects and Assets and the project selection process;
- Maintaining adequate records and internal controls designed to support the Climate Bond Pre-Issuance Certification process; and
- The collection, preparation, and presentation of the subject matter in accordance with the Climate Bonds Standard and Criteria.

Independence and Quality Control

Kestrel provides green, social and sustainability bonds services for corporate and municipal issuers. The Kestrel Verification Team is committed to providing robust, transparent, and accurate verifications. For over 20 years Kestrel has been a trusted advisor to state and local governments, nonprofits, and corporations. Kestrel certifies that there is no affiliation, involvement, financial or non-financial interest in the issuer or the projects discussed. We have no affiliation with any bond counsel, bond insurer, credit rating agency, financial advisor firm, municipal advisory firm, or other intermediary. Accredited as an Approved Verifier by the Climate Bonds Initiative, Kestrel is qualified to evaluate bonds against the Climate Bonds Initiative Standards and Criteria.

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