# SUPPLEMENT DATED MAY 25, 2023

## to the Official Statement dated May 2, 2023

## $506,815,000
## Energy Northwest

**$16,435,000 Project 1 Electric Revenue Refunding Bonds, Series 2023-A**
**$416,180,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A**
**$74,200,000 Project 3 Electric Revenue Refunding Bonds, Series 2023-A**

Energy Northwest hereby amends the following sections of the Official Statement dated May 2, 2023, for the above-referenced bonds.

*The "ENERGY NORTHWEST—The Columbia Generating Station—Nuclear Regulatory Commission Actions" section has been supplemented as shown below (with the additions underlined and the deletions stricken).*

**Nuclear Regulatory Commission Actions**

The NRC is a Federal agency that regulates the design, construction, licensing and operation of nuclear power plants. Once a plant is licensed, one of the major activities of the NRC is the inspection of plant management and operation. The NRC develops policies and administers programs for inspecting licensees to ascertain whether they are complying with NRC regulations, rules, orders and license provisions. The NRC has the authority to suspend, revoke or modify the operating license of commercial nuclear plants to correct deficiencies.

Energy Northwest's activities related to operation and support of Columbia, like those of other licensed nuclear plant operators, are periodically inspected by the NRC. In addition, the NRC normally maintains two on-site resident inspectors who monitor plant activities on a day-to-day basis.

In addition to the day-to-day resident inspector activities, the NRC assesses the performance of nuclear plant operators, including Columbia, by a process known as the Reactor Oversight Process (the "ROP"). The ROP is built upon a framework directly linked to the NRC's mission to protect public health and safety. The framework includes seven cornerstones of safety. Within each cornerstone, a broad sample of information on which to assess plant operator performance in risk-significant areas is gathered. The information is collected from plant performance indicator data submitted by the plant operator and from NRC risk-informed baseline inspections.

The ROP calls for focusing inspections on activities where the potential risks are greater, applying greater regulatory attention to facilities with performance problems and reducing regulatory attention to facilities that perform well, using objective measurements of the performance of nuclear power plants whenever possible, giving the nuclear industry and the public timely and understandable assessments of plant performance, avoiding unnecessary regulatory burdens of nuclear facilities and responding to violations of regulations in a predictable and consistent manner that reflects the safety impact of the violations.

To monitor these seven cornerstones, the NRC assigns colors of Green, White, Yellow or Red to specific performance indicators and inspection findings. For performance indicators, a Green coding indicates performance within an expected performance level in which the related cornerstone objectives are met; White coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; Yellow coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin; and Red coding indicates a significant reduction in safety margin in the area measured by that performance indicator.

For inspection findings, Green findings are indicative of issues that, while they may not be desirable, represent very low safety or security significance. White findings indicate issues that are of low to moderate significance. Yellow findings are issues that are of substantial safety significance. Red findings represent issues that are of high safety significance with a significant reduction in safety margin. On January 13, 2022, the NRC notified Energy Northwest of a preliminary White finding due to failures to implement and follow written procedures for radiation protection, which resulted in uptakes of radioactive materials to two workers <u>during the Columbia 25th refueling outage (R25) in 2021</u> resulting in doses of greater than 700 millirem committed effective dose equivalent. No violation of administrative or federal limits occurred. Energy Northwest discussed the uptake event with the NRC staff on March 1, 2022 at a Regulatory Conference to provide additional information supporting Energy Northwest's perspective that the finding is of very low safety significance, or a Green finding. On April 14, 2022, the NRC informed Energy Northwest that although they committed to provide a final decision within 45 days (from March 1, 2022), they received new information that requires additional review and the final decision is on hold, pending review of the new information. In March 2023, the NRC informed Energy Northwest that active work is still ongoing to finish formal characterization of the uptake event. On May 11, 2023, the NRC informed Energy Northwest that it is expected that the NRC will keep the White finding on the uptake event. The NRC will conduct an inspection to ensure Energy Northwest has addressed the issues before the White finding can be removed. In addition, the NRC informed Energy Northwest that the NRC discovered two additional performance deficiencies in the radiation protection area related to the same preliminary White finding issue. The NRC is currently assessing the severity of these additional performance deficiencies but has indicated that their significance is initially believed to be of low to moderate significance. The NRC will provide preliminary characterization of the new issues by conducting a meeting with Energy Northwest on May 30, 2023. Energy Northwest's response to the new issues may require an additional Regulatory Conference and/or a supplemental inspection. At this time, Energy Northwest is unable to predict whether these additional performance deficiencies would result in White findings. ~~No specific timeline was provided for when Energy Northwest will be provided the results.~~ Prior to this preliminary finding, there were no greater than Green findings at Columbia since a White finding for shipping radioactive material in November 2016 in the incorrect container on public roadways that did not comply with Department of Transportation regulations.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary that can be found on the NRC's website (https://www.nrc.gov/reactors/operating/oversight/actionmatrix-summary.html). The Safeguards (Physical Protection) cornerstone performance indicators and inspection findings are not integrated into the Action Matrix Summary. The Action Matrix Summary reflects overall plant performance, which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance columns.

Best performing plants are included in the Licensee Response Column where routine (baseline) inspection and staff interaction is the norm. The next level of performance is the Regulatory Response Column, which includes plants that have no more than two White inputs in different strategic performance areas. Plants in this column are subject to NRC inspection follow-up of utility corrective actions. There are three remaining Response Columns, including the Unacceptable Performance Column, which includes plants that are not permitted to operate.

As of January 25, 2023, 87 plants, including Columbia, were in the NRC's Regulatory Oversight Process Summary Licensee Response Column, with six plants in the Regulatory Response Column, and no plants in the Multiple/Repetitive Degraded Cornerstone Column, the Degraded Cornerstone Column or the Unacceptable Performance Column. If there is one or two White findings, Columbia would be in the Regulatory Response Column, which could be retroactive from the date of the initial event.

*[remainder of page intentionally left blank]*

*The interest rate of the Columbia 2010-C Bonds is corrected to **4.974%** in the table of "Electric Revenue Bonds to be Currently Refunded" in the "PURPOSE OF ISSUANCE" section of the Official Statement. The amended table with the correction underlined is shown below.*

**Electric Revenue Bonds to be Currently Refunded:**

| Project | Series | Amount | Maturity (July 1) | Interest Rate | Payment or Redemption Date | Redemption Price | CUSIP No. |
|---|---|---|---|---|---|---|---|
| Columbia | 2009-B | $ 4,730,000 | 2024 | 6.800% | 07/01/2023(1) | N/A | 29270CUZ6 |
| Columbia | 2010-C | 15,620,000 | 2023 | <u>4.974</u> | N/A | N/A | 29270CVE2 |
| Columbia | 2012-E | 2,275,000 | 2036(2) | 4.144 | 05/31/2023 | 104.117(3) | 29270CYW9 |
| Columbia | 2012-E | 1,250,000 | 2037(2) | 4.144 | 05/31/2023 | 104.117(3) | 29270CYW9 |
| Columbia | 2014-A | 32,030,000 | 2023 | 5.000 | N/A | N/A | 29270CZV0 |
| Columbia | 2014-A | 540,000 | 2023 | 4.000 | N/A | N/A | 29270CZJ7 |
| Columbia | 2014-B | 40,425,000(4) | 2030 | 4.052 | 05/31/2023 | 102.815(3) | 29270CZB4 |
| Columbia | 2015-A | 20,615,000 | 2023 | 5.000 | N/A | N/A | 29270CJ30 |
| Columbia | 2015-B | 3,165,000 | 2029(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,330,000 | 2030(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,535,000 | 2031(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,810,000 | 2032(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,955,000 | 2033(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,110,000 | 2034(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,260,000 | 2035(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,525,000 | 2036(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,640,000 | 2037(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,940,000 | 2038(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2016-A | 6,330,000 | 2023 | 5.000 | N/A | N/A | 29270CQ57 |
| Columbia | 2017-A | 5,680,000 | 2023 | 5.000 | N/A | N/A | 29270CU94 |
| Columbia | 2018-A | 46,145,000 | 2023 | 5.000 | N/A | N/A | 29270CX42 |
| Columbia | 2018-A | 10,000,000 | 2023 | 4.000 | N/A | N/A | 29270CX59 |
| Columbia | 2018-C | 7,035,000 | 2023 | 5.000 | N/A | N/A | 29270CY74 |
| Columbia | 2019-A | 4,220,000 | 2023 | 5.000 | N/A | N/A | 29270C2P9 |
| Columbia | 2020-A | 1,685,000 | 2023 | 5.000 | N/A | N/A | 29270C3G8 |
| Columbia | 2021-A | 90,905,000 | 2023 | 5.000 | N/A | N/A | 29270C4H5 |
| 3 | 2018-C | 55,225,000 | 2023 | 5.000 | N/A | N/A | 29270CZ65 |
| 3 | 2018-C | 13,050,000 | 2023 | 4.000 | N/A | N/A | 29270CZ73 |

(1) Mandatory sinking fund payment.
(2) Term bonds.
(3) Such Columbia Electric Revenue Bonds will be redeemed on the closing date of May 31, 2023, at their Make-Whole Redemption Price calculated as provided in the resolutions authorizing their issuance. Price includes accrued interest to the redemption date and is rounded to the third decimal place for purposes of this table.
(4) Partial maturity.

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**NEW ISSUE — BOOK-ENTRY ONLY**

*In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2023-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2023-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Special Tax Counsel observes that, for tax years beginning after December 31, 2022, interest on the Series 2023-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax.*

*Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the Series 2023-A Bonds. See "TAX MATTERS" herein.*

ENERGY NORTHWEST

# $506,815,000
# ENERGY NORTHWEST

## $16,435,000 Project 1 Electric Revenue Refunding Bonds, Series 2023-A
## $416,180,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A
## $74,200,000 Project 3 Electric Revenue Refunding Bonds, Series 2023-A

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

The Series 2023-A Bonds (the "Series 2023-A Bonds") are being issued for the purpose (directly or indirectly through repayment of a bond anticipation note) of refunding or paying interest on certain Electric Revenue Bonds issued by Energy Northwest, as more fully described herein. In addition, the Columbia 2023-A Bonds are being issued to finance (directly or indirectly through repayment of a bond anticipation note) certain additions and improvements to the Columbia Generating Station, all as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2023-A Bonds will be issued in fully registered form, registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Series 2023-A Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the registered owner of the Series 2023-A Bonds and nominee of DTC, references herein to holders or registered owners shall mean Cede & Co. and shall not mean the beneficial owners of the Series 2023-A Bonds. Principal of the Series 2023-A Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., as Trustee for the Series 2023-A Bonds. Interest on the Series 2023-A Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2024. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2023-A Bonds will be made to such registered owner, and disbursement of such payments will be the responsibility of DTC and DTC Participants as described herein. See "DESCRIPTION OF THE SERIES 2023-A BONDS—GENERAL—Book-Entry System; Transferability and Registration" and Appendix I—"BOOK-ENTRY SYSTEM" herein.

*The Series 2023-A Bonds are subject to redemption prior to maturity as set forth herein. See* "DESCRIPTION OF THE SERIES 2023-A BONDS—REDEMPTION" *herein.*

**The Series 2023-A Bonds are special revenue obligations of Energy Northwest, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the**

## BONNEVILLE POWER ADMINISTRATION

**("Bonneville") from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The Series 2023-A Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power. Project 1, the Columbia Generating Station and Project 3 are separate projects of Energy Northwest, and each Series of the Series 2023-A Bonds are payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" herein.**

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**MATURITY SCHEDULE — See Inside Cover Page**

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The Series 2023-A Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Garvey P.C., Seattle, Washington, Bond Counsel to Energy Northwest, and to certain other conditions. Certain tax matters will be passed upon by Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville. Certain legal matters will be passed upon for Energy Northwest by its Office of General Counsel and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York, Counsel to the Underwriters. It is expected that the Series 2023-A Bonds will be available for delivery through the facilities of DTC on or about May 31, 2023.

**J.P. Morgan** **Wells Fargo Securities**

**BofA Securities** **Citigroup**

May 2, 2023

**MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS, PRICES AND CUSIP NUMBERS**

**THE SERIES 2023-A BONDS**

**$16,435,000**
**PROJECT 1 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2023-A**

| Year (July 1) | Amount | Interest Rate | Yield | Price | CUSIP No.* |
|---|---|---|---|---|---|
| 2034 | $ 16,435,000 | 5.000% | 2.650% | 120.672%** | 29270C4Z5 |

**$416,180,000**
**COLUMBIA GENERATING STATION ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2023-A**

| Year (July 1) | Amount | Interest Rate | Yield | Price | CUSIP No.* |
|---|---|---|---|---|---|
| 2029 | $ 2,340,000 | 4.000% | 2.510% | 108.355% | 29270C5A9 |
| 2030 | 42,900,000 | 4.000 | 2.510 | 109.612 | 29270C5B7 |
| 2031 | 2,630,000 | 4.000 | 2.570 | 110.375 | 29270C5C5 |
| 2032 | 2,875,000 | 5.000 | 2.540 | 119.840 | 29270C5D3 |
| 2033 | 3,015,000 | 5.000 | 2.590 | 121.264 | 29270C5E1 |
| 2034 | 40,055,000 | 5.000 | 2.650 | 120.672** | 29270C5F8 |
| 2035 | 58,340,000 | 5.000 | 2.800 | 119.208** | 29270C5G6 |
| 2036 | 42,550,000 | 5.000 | 2.960 | 117.669** | 29270C5H4 |
| 2037 | 47,780,000 | 5.000 | 3.100 | 116.342** | 29270C5J0 |
| 2038 | 85,045,000 | 5.000 | 3.230 | 115.126** | 29270C5K7 |
| 2039 | 88,650,000 | 5.000 | 3.300 | 114.478** | 29270C5L5 |

**$74,200,000**
**PROJECT 3 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2023-A**

| Year (July 1) | Amount | Interest Rate | Yield | Price | CUSIP No.* |
|---|---|---|---|---|---|
| 2033 | $ 74,200,000 | 5.000% | 2.590% | 121.264% | 29270C5M3 |

* The CUSIP numbers are provided by CUSIP Global Services ("CGS"), managed on behalf of the American Bankers Association by FactSet Research Systems Inc. The CUSIP numbers are not intended to create a database and do 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 Energy Northwest nor the Underwriters take responsibility for the accuracy of the CUSIP numbers.

** Priced to the July 1, 2033 par call date.

**ENERGY NORTHWEST**
**P.O. Box 968**
**Richland, Washington 99352**
**Telephone (509) 372-5000**

**Executive Board Members**

| | |
|---|---|
| John Saven, Chair | Janet Herrin |
| Curt Knapp, Vice Chair | Johnny (Jack) Janda |
| Bill Gordon, Secretary | Jim Malinowski |
| James Moss, Assistant Secretary | Bill Pitesa |
| Arie Callaghan | Tim Sheldon |
| Marc Daudon | |

**Administrative Staff**

| | |
|---|---|
| Chief Executive Officer | Robert E. Schuetz |
| Executive Vice President/Chief Nuclear Officer | William G. Hettel |
| Site Vice President for Nuclear Operations | Dave P. Brown |
| Vice President for Engineering Projects | Alex L. Javorik |
| Vice President for Corporate Governance; General Counsel | Scott A. Vance |
| Vice President for Corporate Finance, Chief Financial and Risk Officer | Cristina M. Reyff |
| Vice President for Engineering | Jeremy S. Hauger |
| Vice President for Energy Services and Development | Greg V. Cullen |
| General Manager for Corporate Support Services | Steve M. Lorence |

***Financial Advisor***
Public Financial Management, Inc.

***Bond and Disclosure Counsel***
Foster Garvey P.C.

***Trustee for the Series 2023-A Bonds***
The Bank of New York Mellon Trust Company, N.A.

**BONNEVILLE POWER ADMINISTRATION**
**P.O. Box 3621**
**Portland, Oregon 97208**
**Telephone (503) 230-3000**

| | |
|---|---|
| Administrator and Chief Executive Officer | John L. Hairston |
| Chief Operating Officer | Joel D. Cook |
| Chief Administrative Officer | Robin R. Furrer |
| Chief Workforce and Strategy Officer | Daniel M. James |
| Senior Vice President, Power Services | Suzanne B. Cooper |
| Senior Vice President, Transmission Services | Richard L. Shaheen |
| Acting Executive Vice President and Chief Financial Officer | Marcus A. Harris |
| Executive Vice President and Chief Information Officer | Ben L. Berry |
| Executive Vice President of Compliance, Audit and Risk Management | Tom A. McDonald |
| Executive Vice President, Environment, Fish and Wildlife | Scott G. Armentrout |
| Executive Vice President and General Counsel | Marcus H. Chong Tim |

***Special Counsel and Special Tax Counsel***
Orrick, Herrington & Sutcliffe LLP

No dealer, broker, salesperson or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations in connection with the issuance and sale of the Series 2023-A Bonds, other than as contained in this Official Statement, and, if given or made, such other information or representations must not be relied upon as having been authorized by Energy Northwest or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy by, nor shall there be any sale of the Series 2023-A Bonds to, any person in any jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

Except as otherwise noted, the information set forth herein has been furnished by Energy Northwest and Bonneville and includes information obtained from other sources which are believed to be reliable; however the information and expressions of opinion contained herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of Energy Northwest or Bonneville since the date hereof.

None of the information herein was provided by the Participants (as defined under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—General") or the Trustee and none of such entities participated in the preparation of this Official Statement. This Official Statement has not been submitted to such entities for review, comment or approval.

This Official Statement contains statements which, to the extent they are not recitations of historical fact, may 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 Energy Northwest's or Bonneville's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements. Energy Northwest and Bonneville do not plan to issue any updates or revisions to the forward-looking statements.

The Underwriters have provided the following sentence for inclusion in this Official Statement: "The Underwriters have reviewed the information in this Official Statement in accordance with, and as a part of, their respective 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."

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APPENDICES

# OFFICIAL STATEMENT

## $506,815,000

## ENERGY NORTHWEST

**$16,435,000 Project 1 Electric Revenue Refunding Bonds, Series 2023-A**
**$416,180,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A**
**$74,200,000 Project 3 Electric Revenue Refunding Bonds, Series 2023-A**

### INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of the Series 2023-A Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the Series 2023-A Bonds and is qualified in all respects by the more detailed information set forth elsewhere in this Official Statement. Unless otherwise specifically defined, certain capitalized terms used in this Introduction have the meanings given to such terms elsewhere in this Official Statement.

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington, proposes to issue $16,435,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2023-A (the "Project 1 2023-A Bonds"), $416,180,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A (the "Columbia 2023-A Bonds") and $74,200,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2023-A (the "Project 3 2023-A Bonds," and collectively with the Project 1 2023-A Bonds and the Columbia 2023-A Bonds, the "Series 2023-A Bonds").

The Project 1 2023-A Bonds are being issued pursuant to Chapters 39.46, 39.53 and 43.52 of the Revised Code of Washington, as amended (the "Act") and Resolution No. 835 adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 2094 adopted on March 22, 2023, the "Project 1 Electric Revenue Bond Resolution") for the purpose of paying (directly or indirectly through the repayment of all or a portion of any loan evidenced by a bond anticipation note as further described under "PURPOSE OF ISSUANCE") a portion of the interest due on certain indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution, and financing a portion of the costs of issuing the Project 1 2023-A Bonds. Energy Northwest has other indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution, which will be on a parity with the Project 1 2023-A Bonds (the "Project 1 Electric Revenue Bonds"). There are no Project 1 bonds outstanding that have a lien on revenues that is prior to the lien of the Project 1 Electric Revenue Bonds and Energy Northwest has covenanted not to issue any prior lien debt.

The Columbia 2023-A Bonds are being issued pursuant to the Act and Resolution No. 1042 adopted on October 23, 1997 (as amended and supplemented, including by Resolution No. 2095 adopted on March 22, 2023, the "Columbia Electric Revenue Bond Resolution") for the purpose of financing the costs of certain additions and improvements to the Columbia Generating Station (also referred to herein as "Columbia"), refunding certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, paying (directly or indirectly through the repayment of all or a portion of any loan evidenced by a bond anticipation note as further described under "PURPOSE OF ISSUANCE") a portion of the interest due on certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, and financing a portion of the costs of issuing the Columbia 2023-A Bonds. See "PURPOSE OF ISSUANCE." Energy Northwest has other indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, which will be on a parity with the Columbia 2023-A Bonds (the "Columbia Electric Revenue Bonds"). There are no Columbia bonds outstanding that have a lien on revenues that is prior to the lien of the Columbia Electric Revenue Bonds, and Energy Northwest has covenanted not to issue any prior lien debt.

The Project 3 2023-A Bonds are being issued pursuant to the Act and Resolution No. 838 adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 2096 adopted on March 22, 2023, the "Project 3 Electric Revenue Bond Resolution," and collectively with the Project 1 Electric Revenue Bond Resolution and the Columbia Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions") for the purpose of refunding certain indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, paying (directly or indirectly through the repayment of all or a portion of any loan evidenced by a bond anticipation note as further described under "PURPOSE OF ISSUANCE") a portion of the interest due on certain indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, and financing a portion of the costs of issuing the Project 3 2023-A Bonds. Energy Northwest has other indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, which will be on a parity with the Project 3 2023-A Bonds (the "Project 3 Electric Revenue Bonds," and collectively with the Project 1 Electric Revenue Bonds and Columbia Electric Revenue Bonds, the "Electric Revenue Bonds"). There are no Project 3 bonds outstanding that have a lien on revenues that is prior to the lien of the Project 3 Electric Revenue Bonds and Energy Northwest has covenanted not to issue any prior lien debt.

The Electric Revenue Bonds, including the Series 2023-A Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Resolutions are collectively referred to herein as the "Net Billed Bonds."

Energy Northwest has a line of credit maturing on April 30, 2024, pursuant to an Amended and Restated Loan Agreement dated April 30, 2021, between Bank of America, N.A. and Energy Northwest (the "2020A/B Amended and Restated Loan Agreement"), in the amount not to exceed $12,000,000 for Project 1, not to exceed $86,000,000 for Columbia and not to exceed $12,000,000 for Project 3. Energy Northwest's obligation to repay advances under the 2020A/B Amended and Restated Loan Agreement is evidenced by a Project 1 revolving tax-exempt bond anticipation note (the "Project 1 2020 Note"), a Columbia revolving tax-exempt bond anticipation note and a revolving taxable bond anticipation note (together, the "Columbia 2020A/B Notes"), and a Project 3 revolving tax-exempt bond anticipation note (the "Project 3 2020 Note," and, collectively with the Project 1 2020 Note and the Columbia 2020A/B Notes, the "2020A/B Notes").

For additional information relating to the indebtedness to be refunded and other purposes of issuance, see "PURPOSE OF ISSUANCE" in this Official Statement.

**ENERGY NORTHWEST**

Energy Northwest was organized in 1957 as the Washington Public Power Supply System. By resolution of its Executive Board adopted on June 2, 1999, the Washington Public Power Supply System officially changed its name to Energy Northwest. Energy Northwest now has 28 members, consisting of 23 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Public Utility District No. 1 of Douglas County joined Energy Northwest in October 2022. Energy Northwest has the authority, among other things, to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power and energy and to issue bonds and other evidences of indebtedness to finance the same.

Energy Northwest owns and operates the Columbia Generating Station, a nuclear electric generating station with a current net design electric rating of 1,174 megawatts ("MW"). Energy Northwest also owns and operates a hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), that generates 26 MW of electricity. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 63 turbines and is capable of generating approximately 96 MW of electricity. In addition, Energy Northwest owned and has financial responsibility for four other nuclear electric generating projects that have been terminated: Energy Northwest Nuclear Project No. 1 ("Project 1"), Energy Northwest Nuclear Project No. 3 ("Project 3") and Energy Northwest Nuclear Projects Nos. 4 and 5 ("Projects 4 and 5"). Project 1 and Project 3 were terminated in 1994, and Projects 4 and 5 were terminated in 1982. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "ENERGY NORTHWEST—PROJECT 1," "—PROJECT 3," and "—PROJECTS 4 AND 5" in this Official Statement. Project 1, Project 3 and Columbia are individually referred to herein as a "Net Billed Project" or a "Project" and collectively referred to herein as the "Net Billed Projects." Each of Project 1, Project 3 and Columbia is financed and accounted for as a separate utility system. Projects 4 and 5 were financed and accounted for as a single utility system separate and apart from all other Energy Northwest projects. All of Energy Northwest's projects are located in the State of Washington. For additional information relating to Energy Northwest, see "ENERGY NORTHWEST" in this Official Statement.

The United States of America, Department of Energy ("DOE"), acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), has acquired the capability of the Net Billed Projects. As more fully discussed under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS," Bonneville is obligated to meet the costs of such capability pursuant to Net Billing Agreements (hereinafter defined) for the Net Billed Projects, with payments being made through a combination of credits against customer bills and cash payments from the Bonneville Fund (hereinafter defined). Bonneville's obligations to make such credits and cash payments under the Net Billing Agreements continue notwithstanding suspension or termination of any of the Net Billed Projects.

**THE BONNEVILLE POWER ADMINISTRATION**

The information under this heading has been derived from information provided to Energy Northwest by Bonneville. For detailed information with respect to Bonneville, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" in this Official Statement.

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 31 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally-owned projects, including the Columbia Generating Station. Bonneville sells and/or exchanges power under contracts with over 125 utilities in the Pacific Northwest and Pacific Southwest and with several industrial customers. It also owns and operates a high voltage transmission system comprising more than 15,000 circuit miles of high voltage transmission lines in the Pacific Northwest.

Bonneville's primary customer service area is the Pacific Northwest region, an area comprised of Oregon, Washington, Idaho, parts of western Montana and small parts of western Wyoming, northern Nevada, northern Utah and northern California (sometimes referred to herein as the "Pacific Northwest," the "Northwest," the "Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately 15 million people. Electric power sold by Bonneville accounts for approximately 28% of the electric power consumed within the Region. Bonneville also exports power that is surplus to the needs of the Region to the Pacific Southwest, primarily to California.

Bonneville is one of four regional Federal power marketing administrations within the DOE. Bonneville is required by law to meet certain energy requirements in the Region and is authorized to acquire power resources, to implement conservation measures and to take other actions to enable it to carry out its purposes. Bonneville is also required by law to operate and maintain its transmission system and to provide transmission service to eligible customers and to undertake certain other programs, such as fish and wildlife protection, mitigation and enhancement.

**THE SERIES 2023-A BONDS**

The Project 1 2023-A Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2023-A Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1 on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

The Columbia 2023-A Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2023-A Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of the Columbia Generating Station on a parity with the Columbia Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

The Project 3 2023-A Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2023-A Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3 on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

There are no restrictions on the issuance of debt under the Electric Revenue Bond Resolutions or pursuant to any of the above mentioned Separate Resolutions, so long as the Net Billing Agreements and the other Project agreements are in effect and no event of default is existing under the applicable Electric Revenue Bond Resolutions. See "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS" in this Official Statement.

Energy Northwest has covenanted that it will not issue any Project 1 bonds or other debt with a lien on Project 1 revenues superior to the Project 1 Electric Revenue Bonds; any Columbia bonds or other debt with a lien on Columbia Generating Station revenues superior to the Columbia Electric Revenue Bonds; or any Project 3 bonds or other debt with a lien on Project 3 revenues superior to the Project 3 Electric Revenue Bonds.

The Project 1 2023-A Bonds are secured by amounts derived pursuant to the Project 1 Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The Columbia 2023-A Bonds are secured by amounts derived pursuant to Net Billing Agreements related to the Columbia Generating Station with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The Project 3 2023-A Bonds are secured by amounts derived pursuant to the Project 3 Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The receipts, income and revenues derived from a Project secure only the Series 2023-A Bonds and other Electric Revenue Bonds relating to that Project. Accordingly, the owners of the Series 2023-A Bonds issued for a particular Project will have no claim on the receipts, income and revenues securing any other Energy Northwest Project. For further information, see "SECURITY FOR THE NET BILLED BONDS" in this Official Statement.

For further information on the Net Billed Bonds outstanding as of March 31, 2023, see "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" in this Official Statement.

## NET BILLING AGREEMENTS

Under the Net Billing Agreements, the Participants in each Net Billed Project have contracted to purchase the capability of that Net Billed Project and have agreed to provide Energy Northwest with funds necessary to meet the costs of that Net Billed Project. These costs include the amounts that Energy Northwest is obligated to pay in each contract year into the various funds provided for in the Project 1 Electric Revenue Bond Resolution for debt service and for all other purposes of Project 1; in the Columbia Electric Revenue Bond Resolution for debt service and for all other purposes of Columbia; and in the Project 3 Electric Revenue Bond Resolution for debt service and for all other purposes of Project 3. The Net Billing Agreements also effected a simultaneous assignment of the Project capability from the Participants to Bonneville and created an obligation of Bonneville to pay the Participants (from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund, as described herein) for their respective shares of the costs of the Net Billed Projects. Thus, Bonneville is ultimately obligated to meet such costs.

Under the Net Billing Agreements, payments to Energy Northwest generally are required to be made directly by the Participants, not directly by Bonneville. Such payments by the Participants are to be made in accordance with each Participant's participation in the purchase of the capability of the Net Billed Project. Bonneville is required to pay for the capability of the Net Billed Project assigned by the Participants to it by crediting (or net billing) Bonneville's bills to Participants for power and other services purchased by Participants from Bonneville by the amount of the payment required to be made by the Participants to Energy Northwest. To the extent that the total amount of Bonneville's bills to each Participant (and consequently the amount of such credit available) over a contract year (July 1 to June 30) is less than the payment required to be made by the Participant to Energy Northwest, Bonneville is obligated to pay the deficiency in cash to the Participant from the Bonneville Fund. 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 cash payment obligations of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. Net proceeds 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: (1) the repayment of the Federal investment in certain transmission facilities and the power-generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (2) debt service on bonds issued by Bonneville and sold to the United States Treasury; (3) repayments of appropriated amounts to the Corps and the Bureau for certain costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (4) costs allocated to irrigation projects as are required by law to be recovered from power sales.

Cash payments and the provision of credits by Bonneville and payments by Participants under each Net Billing Agreement are required whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of Net Billed Project output or termination of the related 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.

*Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.*

As described under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Direct Pay Agreements," in 2006 Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project pursuant to which Bonneville pays at least monthly all costs for each Net Billed Project directly to Energy Northwest. One effect of the Direct Payment Agreements is that each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. The Direct Pay Agreements do not amend the Net Billing Agreements. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

For further information as to the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS," "LEGAL MATTERS" and Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS" in this Official Statement. For information with respect to Bonneville, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" in this Official Statement.

# DESCRIPTION OF THE SERIES 2023-A BONDS

## GENERAL

The Series 2023-A Bonds are dated the date of their delivery, and mature on July 1 in the years and in the principal amounts shown on the inside cover page of this Official Statement. The Series 2023-A Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2024, at the rates shown on the inside cover page of this Official Statement. Interest on the Series 2023-A Bonds will be calculated based on a 360-day year consisting of twelve 30-day months. The Bank of New York Mellon Trust Company, N.A. has been appointed the Trustee, Paying Agent and Registrar for the Series 2023-A Bonds (collectively, the "Trustee"). For so long as the Series 2023-A Bonds are registered in the name of Cede & Co. (as nominee of The Depository Trust Company, New York, New York ("DTC")) or its registered assigns, payments of principal and interest shall be made in accordance with the operational arrangements of DTC.

**Book-Entry System; Transferability and Registration**

The Series 2023-A Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the Series 2023-A Bonds will not receive certificates representing their interests in such Series 2023-A Bonds purchased, except as described in Appendix I—"BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as initial securities depository for each Series of Series 2023-A Bonds. As discussed in Appendix I—"BOOK-ENTRY SYSTEM," transfers of ownership interests in the Series 2023-A Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants (as defined in Appendix I—"BOOK-ENTRY SYSTEM") acting on behalf of Beneficial Owners of the Series 2023-A Bonds. Energy Northwest, the Trustee and any other person may treat the registered owner of any Series 2023-A Bonds as the absolute owner of such Series 2023-A Bonds for the purpose of making payment thereof and for all other purposes, and Energy Northwest and the Trustee shall not be bound by any notice or knowledge to the contrary, whether such Series 2023-A Bonds shall be overdue or not. All payments of or on account of interest or principal to any registered owner of any such Series 2023-A Bonds shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such Series 2023-A Bonds, to the extent of the sum or sums paid.

When Series 2023-A Bonds are registered in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Trustee shall have no responsibility or obligation to any DTC Participant or to any person on behalf of whom a DTC Participant holds an interest in the Series 2023-A Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the Series 2023-A Bonds, (2) the delivery to any DTC Participant or any other person, other than a registered owner as shown on the bond register, of any notice with respect to the Series 2023-A Bonds, including any notice of redemption, (3) the payment to any DTC Participant or any other person, other than a registered owner as shown on the bond register, of any amount with respect to principal of, premium, if any, or interest on the Series 2023-A Bonds, (4) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the Series 2023-A Bonds, (5) any consent given or action taken by DTC as registered owner, or (6) any other matter. Energy Northwest and the Trustee may treat and consider Cede & Co., in whose name each Series 2023-A Bond is registered, as the holder and absolute owner of such Series 2023-A Bond for the purpose of payment, giving notices of redemption and other matters.

**Discontinuation of Book-Entry Transfer System**

If Energy Northwest determines to discontinue the book-entry system of transfer, Energy Northwest is required to execute, authenticate and deliver at no cost to the beneficial owners of the Series 2023-A Bonds, Series 2023-A Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the Series 2023-A Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the Series 2023-A Bonds will be payable by check or draft mailed to the persons in whose names such Series 2023-A Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date; provided, however, that upon the written request of a registered owner of at least $1,000,000 in aggregate principal amount of a Series of the Series 2023-A Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. If the book-entry transfer system for the Series 2023-A Bonds is discontinued, registered ownership of any Series 2023-A Bond may be transferred or exchanged by surrendering such Series 2023-A Bond to the Trustee, with the assignment form appearing on the Series 2023-A Bond duly executed. The Trustee shall not be required to transfer any Series 2023-A Bond during the 15 days preceding an interest payment or redemption date.

## REDEMPTION

**Optional Redemption**

The Series 2023-A Bonds maturing on and after July 1, 2034, are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2033, in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at a Redemption Price equal to 100% of the principal amount of the Series 2023-A Bonds to be redeemed, plus interest accrued to the date of redemption.

**Partial Redemption**

If less than all of the Series 2023-A Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities, including any sinking fund redemptions of Term Bonds, to be redeemed. If less than all of the Series 2023-A Bonds of any maturity are to be redeemed, the Series 2023-A Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any Series 2023-A 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 2023-A Bonds for redemption, the Trustee will treat each such Series 2023-A Bond as representing that number of such Series 2023-A Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2023-A Bonds to be redeemed in part by $5,000.

**Notice of Redemption**

Notice of redemption of any Series 2023-A Bonds is to be given by the Trustee by first-class mail not less than 20 days nor more than 60 days before the redemption date to the registered owners of the Series 2023-A Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2023-A Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2023-A Bonds which are to be redeemed, whether or not such notice is actually received. Mailing of such notice of redemption shall not be a condition precedent to such redemption, and failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the Series 2023-A Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2023-A 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 2023-A Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee on the redemption date and the Series 2023-A Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. Energy Northwest may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation 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 system is in effect with respect to the Series 2023-A Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2023-A Bonds of a maturity are to be redeemed, DTC or its successor and DTC Participants and Indirect Participants (as such terms are defined in Appendix I—"BOOK-ENTRY SYSTEM") will determine the particular ownership interests of Series 2023-A 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 2023-A Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2023-A Bonds.

Neither Energy Northwest, the Trustee, nor the Underwriters can give any assurance that DTC, the DTC Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2023-A Bonds, or that they will do so on a timely basis.

**Open Market Purchases**

Energy Northwest has reserved the right to purchase any Series 2023-A Bonds on the open market at any time and at any price.

## DEFEASANCE

The liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Project 1 Electric Revenue Bond Resolution, the Columbia Electric Revenue Bond Resolution or the Project 3 Electric Revenue Bond Resolution shall be fully discharged and satisfied as to any related Series 2023-A Bond, and such Series 2023-A Bond shall no longer be deemed to be outstanding under the Project 1 Electric Revenue Bond Resolution, Columbia Electric Revenue Bond Resolution or Project 3 Electric Revenue Bond Resolution, as applicable, when payment of principal of and premium, if any, on such Series 2023-A Bond, plus interest on such principal to the date thereof shall have been made or shall have been provided for by irrevocably depositing with the Trustee or a separate paying agent for such Series 2023-A Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) money sufficient to make such payment, or (2) specified "defeasance obligations" maturing or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will assure the availability of sufficient money to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agent pertaining to such Series 2023-A Bond. Defeasance obligations are defined in RCW 39.53 and include direct obligations of the United States and certain obligations of United States agencies and instrumentalities and others as defined under "Government Obligations" in Appendix H. See Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Defeasance (Article XI)" for a discussion of defeasance of the Series 2023-A Bonds.

## PURPOSE OF ISSUANCE

The Project 1 2023-A Bonds are being issued for the purpose of paying (directly or indirectly through repayment of the Project 1 2020 Note as described below) a portion of the interest due on outstanding Project 1 Electric Revenue Bonds previously paid or due on July 1, 2023, and paying the costs of issuing the Project 1 2023-A Bonds.

Pursuant to the 2020A/B Amended and Restated Loan Agreement, Energy Northwest borrowed $9,936,000 to repay a portion of the interest due on certain Project 1 Electric Revenue Bonds. Energy Northwest's obligation to repay the advance under the 2020A/B Amended and Restated Loan Agreement for this purpose is evidenced by the Project 1 2020 Note. The Project 1 2020 Note is secured on a parity with the Project 1 Electric Revenue Bonds issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Project 1 Separate Subordinated Resolutions.

The Columbia 2023-A Bonds are being issued for the purpose of currently refunding $329,755,000 aggregate principal amount of the Columbia Electric Revenue Bonds, paying (directly or indirectly through repayment of the Columbia 2020A/B Notes as described below) a portion of the interest due on outstanding Columbia Electric Revenue Bonds previously paid or due on July 1, 2023, and paying the costs of issuing the Columbia 2023-A Bonds. The Columbia 2023-A Bonds are also being issued for the purpose of financing certain additions and improvements to the Columbia Generating Station.

Pursuant to the 2020A/B Amended and Restated Loan Agreement, Energy Northwest borrowed $26,795,000 of the tax-exempt portion to repay a portion of the interest due on certain Columbia Electric Revenue Bonds. Energy Northwest's obligation to repay the tax-exempt advance under the 2020A/B Amended and Restated Loan Agreement for this purpose is evidenced by the tax-exempt portion of the Columbia 2020A/B Notes.

The Columbia 2020A/B Notes are secured on a parity with the Columbia Electric Revenue Bonds issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Columbia Separate Subordinated Resolutions.

The Project 3 2023-A Bonds are being issued for the purpose of currently refunding $68,275,000 aggregate principal amount of the Project 3 Electric Revenue Bonds, paying (directly or indirectly through repayment of the Project 3 2020 Note as described below) a portion of the interest due on outstanding Project 3 Electric Revenue Bonds previously paid or due on July 1, 2023, and paying the costs of issuing the Project 3 2023-A Bonds.

Pursuant to the 2020A/B Amended and Restated Loan Agreement, Energy Northwest borrowed $10,798,000 to repay a portion of the interest due on certain Project 3 Electric Revenue Bonds. Energy Northwest's obligation to repay the advance under the 2020A/B Amended and Restated Loan Agreement for this purpose is evidenced by the Project 3 2020 Note. The Project 3 2020 Note is secured on a parity with the Project 3 Electric Revenue Bonds issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Project 3 Separate Subordinated Resolutions.

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A portion of the proceeds of the Series 2023-A Bonds, together with other available amounts, and available funds of Energy Northwest, where applicable, will be used to refund or pay at maturity all of the following Electric Revenue Bonds:

**Electric Revenue Bonds to be Currently Refunded:**

| Project | Series | Amount | Maturity (July 1) | Interest Rate | Payment or Redemption Date | Redemption Price | CUSIP No. |
|---|---|---|---|---|---|---|---|
| Columbia | 2009-B | $ 4,730,000 | 2024 | 6.800% | 07/01/2023(1) | N/A | 29270CUZ6 |
| Columbia | 2010-C | 15,620,000 | 2023 | 4.975 | N/A | N/A | 29270CVE2 |
| Columbia | 2012-E | 2,275,000 | 2036(2) | 4.144 | 05/31/2023 | 104.117(3) | 29270CYW9 |
| Columbia | 2012-E | 1,250,000 | 2037(2) | 4.144 | 05/31/2023 | 104.117(3) | 29270CYW9 |
| Columbia | 2014-A | 32,030,000 | 2023 | 5.000 | N/A | N/A | 29270CZV0 |
| Columbia | 2014-A | 540,000 | 2023 | 4.000 | N/A | N/A | 29270CZJ7 |
| Columbia | 2014-B | 40,425,000(4) | 2030 | 4.052 | 05/31/2023 | 102.815(3) | 29270CZB4 |
| Columbia | 2015-A | 20,615,000 | 2023 | 5.000 | N/A | N/A | 29270CJ30 |
| Columbia | 2015-B | 3,165,000 | 2029(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,330,000 | 2030(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,535,000 | 2031(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,810,000 | 2032(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 3,955,000 | 2033(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,110,000 | 2034(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,260,000 | 2035(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,525,000 | 2036(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,640,000 | 2037(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2015-B | 4,940,000 | 2038(2) | 3.843 | 05/31/2023 | 101.760(3) | 29270CL45 |
| Columbia | 2016-A | 6,330,000 | 2023 | 5.000 | N/A | N/A | 29270CQ57 |
| Columbia | 2017-A | 5,680,000 | 2023 | 5.000 | N/A | N/A | 29270CU94 |
| Columbia | 2018-A | 46,145,000 | 2023 | 5.000 | N/A | N/A | 29270CX42 |
| Columbia | 2018-A | 10,000,000 | 2023 | 4.000 | N/A | N/A | 29270CX59 |
| Columbia | 2018-C | 7,035,000 | 2023 | 5.000 | N/A | N/A | 29270CY74 |
| Columbia | 2019-A | 4,220,000 | 2023 | 5.000 | N/A | N/A | 29270C2P9 |
| Columbia | 2020-A | 1,685,000 | 2023 | 5.000 | N/A | N/A | 29270C3G8 |
| Columbia | 2021-A | 90,905,000 | 2023 | 5.000 | N/A | N/A | 29270C4H5 |
| 3 | 2018-C | 55,225,000 | 2023 | 5.000 | N/A | N/A | 29270CZ65 |
| 3 | 2018-C | 13,050,000 | 2023 | 4.000 | N/A | N/A | 29270CZ73 |

(1) Mandatory sinking fund payment.
(2) Term bonds.
(3) Such Columbia Electric Revenue Bonds will be redeemed on the closing date of May 31, 2023, at their Make-Whole Redemption Price calculated as provided in the resolutions authorizing their issuance. Price includes accrued interest to the redemption date and is rounded to the third decimal place for purposes of this table.
(4) Partial maturity.

A portion of the proceeds of the Series 2023-A Bonds, together with other available amounts, and available funds of Energy Northwest, where applicable, will be deposited in a refunding account or the respective debt service accounts for each Series of Refunded Bonds to be refunded and may be, at the direction of Energy Northwest, used to purchase certain investment securities permitted by the Electric Revenue Bond Resolutions. The amounts deposited in the refunding accounts, debt service accounts or used to purchase investment securities, together with the interest to accrue thereon, will be applied to pay the principal or redemption price, if any, and all or a portion of the interest on the Electric Revenue Bonds to be refunded as set forth in the table above. The Bond Fund Trustee for the Electric Revenue Bonds will give notice of redemption of such Electric Revenue Bonds to be redeemed when and as provided in the Electric Revenue Bond Resolutions.

## SOURCES AND USES OF FUNDS[1]

### SOURCES OF FUNDS

| | |
|---|---|
| **Project 1** | |
| Principal of Project 1 2023-A Bonds | $ 16,435,000 |
| Original Issue Premium | 3,397,443 |
| Energy Northwest Contribution | 75,377 |
| Total | $ 19,907,820 |
| **Columbia** | |
| Principal of Columbia 2023-A Bonds | $ 416,180,000 |
| Original Issue Premium | 66,314,565 |
| Energy Northwest Contribution | 10,458,903 |
| Total | $ 492,953,467 |
| **Project 3** | |
| Principal of Project 3 2023-A Bonds | $ 74,200,000 |
| Original Issue Premium | 15,777,888 |
| Energy Northwest Contribution | 192,810 |
| Total | $ 90,170,698 |

### USES OF FUNDS

| | |
|---|---|
| **Project 1** | |
| Deposit with trustee to pay interest on Project 1 Electric Revenue Bonds | $ 9,859,489 |
| Project 1 2020 Note Repayment | 9,936,000 |
| Costs of issuing Project 1 2023-A Bonds (including Underwriters' compensation) | 112,331 |
| Total | $ 19,907,820 |
| **Columbia** | |
| Deposit into Construction Account | $ 106,053,312 |
| Deposit with trustee to currently refund Columbia Electric Revenue Bonds | 330,739,755 |
| Deposit with trustee to pay interest on Columbia Electric Revenue Bonds | 26,632,552 |
| Columbia 2020A/B Notes Repayment | 26,795,000 |
| Costs of issuing Columbia 2023-A Bonds (including Underwriters' compensation) | 2,732,848 |
| Total | $ 492,953,467 |
| **Project 3** | |
| Deposit with trustee to currently refund Project 3 Electric Revenue Bonds | $ 67,994,951 |
| Deposit with trustee to pay interest on Project 3 Electric Revenue Bonds | 10,868,112 |
| Project 3 2020 Note Repayment | 10,798,000 |
| Costs of issuing Project 3 2023-A Bonds (including Underwriters' compensation) | 509,635 |
| Total | $ 90,170,698 |

(1) Totals may not add due to rounding.

## SECURITY FOR THE NET BILLED BONDS

### PLEDGE OF REVENUES AND PRIORITY

The Project 1 2023-A Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 1 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2023-A Bonds are a charge on the receipts, income and revenues of Project 1 subordinate to the payments to be made with respect to Energy Northwest's cost of operating and maintaining Project 1, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The

Project 1 Electric Revenue Bonds, including the Project 1 2023-A Bonds, are also secured by a pledge of the proceeds of the sale of Project 1 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 1 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 1 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 1 Electric Revenue Bond Resolution, the Project 1 2023-A Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 1 Separate Resolution. There were outstanding as of March 31, 2023, $792,710,000 principal amount of Project 1 Electric Revenue Bonds. There are no Project 1 bonds outstanding that have a lien on Project 1 revenues that is prior to the lien of the Project 1 Electric Revenue Bonds.

The Columbia 2023-A Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Columbia Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Columbia. The Columbia 2023-A Bonds are a charge on the receipts, income and revenues of Columbia subordinate to the payments required to be made with respect to Energy Northwest's cost of operating and maintaining Columbia, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Columbia Electric Revenue Bonds, including the Columbia 2023-A Bonds, are also secured by a pledge of the proceeds of the sale of Columbia Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Columbia Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Columbia Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Columbia Electric Revenue Bond Resolution, the Columbia 2023-A Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Columbia Separate Resolution. There were outstanding as of March 31, 2023, $3,096,640,000 principal amount of Columbia Electric Revenue Bonds. There are no Columbia bonds outstanding that have a lien on Columbia Generating Station revenues that is prior to the lien of the Columbia Electric Revenue Bonds.

The Project 3 2023-A Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 3 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2023-A Bonds are a charge on the receipts, income and revenues of Project 3 subordinate to the payments to be made with respect to Energy Northwest's cost of operating and maintaining Project 3, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 3 Electric Revenue Bonds, including the Project 3 2023-A Bonds, are also secured by a pledge of the proceeds of the sale of Project 3 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 3 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 3 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 3 Electric Revenue Bond Resolution, the Project 3 2023-A Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 3 Separate Resolution. There were outstanding as of March 31, 2023, $944,820,000 principal amount of Project 3 Electric Revenue Bonds. There are no Project 3 bonds outstanding that have a lien on Project 3 revenues that is prior to the lien of the Project 3 Electric Revenue Bonds.

Energy Northwest has covenanted with the owners of the Project 1 Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Project 1 revenues prior to the Project 1 Electric Revenue Bonds, has covenanted with the owners of the Columbia Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Columbia Generating Station revenues prior to the Columbia Electric Revenue Bonds, and has covenanted with the owners of the Project 3 Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Project 3 revenues prior to the Project 3 Electric Revenue Bonds.

Amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 1 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 1 2023-A Bonds. Energy Northwest is obligated to pay to the Trustee for the Project 1 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Project 1 Electric Revenue Bonds, including the Project 1 2023-A Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

Amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements entered into among Energy Northwest, Bonneville and the Columbia Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Columbia 2023-A Bonds. Energy Northwest is obligated to pay to the Trustee for the Columbia Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Columbia Electric Revenue Bonds, including the Columbia 2023-A Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

Amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 3 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 3 2023-A Bonds. Energy Northwest is obligated to pay to the Trustee for the Project 3 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Project 3 Electric Revenue Bonds, including the Project 3 2023-A Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

Bonneville may make only such expenditures from the Bonneville Fund as shall have been included in budgets submitted annually to Congress. Bonneville includes in its annual budget submittal to Congress information sufficient to cover its obligations under the Net Billing Agreements, including the payment of debt service on the Net Billed Bonds. Bonneville may make such expenditures without further appropriation and without fiscal year limitation, but subject to such specific directives or limitations on use of the Bonneville Fund as may be included by Congress in appropriation acts. 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—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund" in this Official Statement.

The Project 1 2023-A Bonds, the Columbia 2023-A Bonds and the Project 3 2023-A Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2023-A Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2023-A Bonds and the Project 3 2023-A Bonds. The owners of the Columbia 2023-A Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2023-A Bonds and the Project 3 2023-A Bonds. The owners of the Project 3 2023-A Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2023-A Bonds and the Columbia 2023-A Bonds. No Bondholder has a claim on the assets of any Project.

*The Series 2023-A Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power.*

See Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

**EVENTS OF DEFAULT AND REMEDIES**

For a description of the events of default and remedies applicable to the Electric Revenue Bonds, including the Series 2023-A Bonds, see Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Events of Default and Remedies (Section 801)."

If the maturity of Electric Revenue Bonds, including the Series 2023-A Bonds, were accelerated by the applicable Bond Fund Trustee or Trustee or the holders of the requisite principal amount of such bonds after an Event of Default under the respective Electric Revenue Bond Resolution, no assurance can be given that the principal amount of the accelerated Electric Revenue Bonds would be payable currently as a cost under the terms of the Net Billing Agreements related to such Net Billed Project. See "—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" and "—LIMITATIONS ON REMEDIES" for a discussion of the limitations of certain remedies.

If there is an acceleration of a maturity of the Electric Revenue Bonds, Bonneville has taken the position since at least 1989 that Bonneville's and the Participants' obligations to make payments under the Net Billing Agreements would remain as though no such acceleration had occurred.

Payments and the provision of credits by Bonneville and payments by Participants under the Net Billing Agreements relating to the Net Billed Projects that are required to be made to Energy Northwest to pay the principal of and interest on the outstanding Net Billed Bonds issued for the related Net Billed Project are required to be made notwithstanding the occurrence of an Event of Default.

**LIMITATIONS ON REMEDIES**

Upon the occurrence of an Event of Default under the Electric Revenue Bond Resolutions, payment of the principal of and interest on the Series 2023-A Bonds may be accelerated. Any action to compel payment for money damages or to accelerate payment would be subject to the limitations on legal claims and remedies against public bodies under Washington law. The right to accelerate payments by a Washington municipality has not been tested by any Washington court. Any remedies available to Bondholders are in many respects dependent upon judicial actions, which are in turn often subject to discretion and delay and can be expensive and time-consuming to obtain. If Energy Northwest fails to comply with its covenants under the Electric Revenue Bond Resolutions or to pay principal of or interest on the Series 2023-A Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the Series 2023-A Bonds. See "—EVENTS OF DEFAULT AND REMEDIES" for a discussion of possible limits of amounts payable under the Net Billing Agreements in the event of acceleration of the Net Billed Bonds.

In addition to the limitations on remedies in the Electric Revenue Bond Resolutions, the rights and obligations under the Series 2023-A Bonds may be limited by and are subject to bankruptcy, insolvency, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases. The opinions to be delivered by Foster Garvey P.C., as Bond Counsel, concurrently with the issuance of the Series 2023-A Bonds will be subject to such limitations. See Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2023-A BONDS," and Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2023-A BONDS."

**NO RESERVE ACCOUNT**

There is no reserve account securing repayment of the Series 2023-A Bonds. In the Electric Revenue Bond Resolutions, Energy Northwest has reserved the right to create a reserve account to secure a separate series of Electric Revenue Bonds.

**ADDITIONAL INDEBTEDNESS**

In each Electric Revenue Bond Resolution, Energy Northwest has reserved the right to issue, upon satisfaction of certain conditions set forth therein, additional bonds or notes under the Electric Revenue Bond Resolutions or under one or more separate resolutions ("Separate Resolutions") of the Executive Board creating a pledge of and lien on the receipts, income and revenues derived from the related Project of equal rank with the pledge and lien created by such Electric Revenue Bond Resolution in favor of the Electric Revenue Bonds. The 2020A/B Notes were issued pursuant to related Separate Resolutions. See "INTRODUCTION." There are no restrictions on or conditions to issuing debt on a parity with the Electric Revenue Bonds under the Electric Revenue Bond Resolutions, including the Series 2023-A Bonds, pursuant to Separate Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist under the applicable Electric Revenue Bond Resolution. There are no Project 1, Columbia or Project 3 prior lien bonds.

Conditions to the issuance of additional bonds pursuant to the Electric Revenue Bond Resolutions are described in Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

Each of the Electric Revenue Bond Resolutions permits the use of certain credit facilities to secure the payment of the related Electric Revenue Bonds and the incurrence by Energy Northwest of reimbursement obligations of the type referred to in such Electric Revenue Bond Resolution to reimburse the issuer of a credit facility. Each of the Electric Revenue Bond Resolutions also permits the use of interest rate exchange agreements or similar agreements. Such reimbursement obligations or obligations of Energy Northwest under such interest rate exchange agreements, including any termination payments owed by Energy Northwest, may be secured on a parity with the lien created by the applicable Electric Revenue Bond Resolution in favor of the related Electric Revenue Bonds. See Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

For information regarding the amount of bonds and other obligations of Energy Northwest outstanding under the Electric Revenue Bond Resolutions and Separate Resolutions, see "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS."

**NET BILLING AND RELATED AGREEMENTS**

**General**

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 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. See Appendix F—"ENERGY NORTHWEST PARTICIPANT UTILITY SHARE OF FISCAL YEAR 2023 BUDGETS" for a list of Participants and their respective shares of the Projects' fiscal year 2023 budgets.

Under the Net Billing Agreements, in payment for the share of the capability of each 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 Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement referred to below under "Payment Procedures." 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 (subject to the limitations described herein under Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL

OPERATIONS—The Bonneville Fund"). 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 Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Net Billed Project output or termination of the related 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 or accounting 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 authority of all of the Participants to enter into the Net Billing Agreements was affirmed in 1985 by the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System, et al.* (the "Springfield Case"). The United States Supreme Court denied a petition for a writ of certiorari. In upholding the Net Billing Agreements, the court in the Springfield Case found that the Net Billing Agreements are contracts for the purchase of electricity because the Net Billing Agreements place the dry hole risk on Bonneville and not on the Participants and because the Participants will receive either electricity or a cash refund equal to their payments to Energy Northwest. For a discussion of Bond Counsel's opinion with respect to the enforceability of the Net Billing Agreements, see "LEGAL MATTERS." For a summary of certain provisions of the Net Billing Agreements, see Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

Pending the receipt of the ruling in the Springfield Case, Energy Northwest and Bonneville entered into certain Assignment Agreements for each of Project 1, Columbia and Project 3 (the "Assignment Agreements"). For additional information with respect to the Assignment Agreements, see "—Assignment Agreements" and Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

By letter dated August 1, 1989 (the "1989 Letter Agreement"), Bonneville 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 Bonneville, Bonneville will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the Net Billing Agreements.

As described under "Direct Pay Agreements," Energy Northwest and Bonneville executed an agreement with respect to each Net Billed Project pursuant to which Bonneville agrees to monthly pay all costs for each Net Billed Project directly to Energy Northwest and each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

All payments required to be made by Bonneville under the Net Billing Agreements, the Assignment Agreements, the 1989 Letter Agreement and the Direct Pay Agreements are to be made from the Bonneville Fund or other funds legally available therefor. See "—THE BONNEVILLE FUND" below.

*Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.*

**Payment Procedures**

The Columbia Net Billing Agreements provide for the adoption by Energy Northwest of an Annual Budget, which, as amended from time to time, shall make provision for all Columbia costs, including, but not limited to, the amounts which Energy Northwest is required to pay in each contract year (July 1 to June 30) into the various funds provided for in the Columbia Electric Revenue Bond Resolution for debt service and all other purposes. The Annual Budget also includes the source of funds proposed to be used. The Annual Budget is submitted to Bonneville and to the Participants' Review Board established under the Columbia Net Billing Agreements and becomes effective 30 days after submitted unless it is disapproved by Bonneville or unless a recommendation or modification proposed by the Participants' Review Board is not accepted by Energy Northwest. In the event of a dispute, the matter is referred to a Project Consultant as described in Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS—The Project Agreements." Energy Northwest prepares a Billing Statement for that contract year for each Columbia Participant. The Billing Statement shows such Participant's share of the Annual Budget for Columbia less amounts payable from sources other than the Columbia Net Billing Agreements. The Annual Budget and Billing

Statements may be amended during a contract year, if necessary. As described below, each Participant makes monthly payments to Energy Northwest in satisfaction of the amounts due under its Billing Statement.

In the month preceding the beginning of each contract year and in each month thereafter, Bonneville renders a bill to each Participant for power and other services under the Participant's power sales and other contracts with Bonneville. In the first month of the contract year, that bill shows an offsetting credit equal to the full amount of such bill to the extent of the Participant's share of the costs of Columbia. Within 30 days of receiving the monthly bill from Bonneville reflecting such credit, the Participant must pay Energy Northwest an amount equal to the credit for Columbia received from Bonneville. In each month thereafter during the contract year, such crediting by Bonneville and such payments to Energy Northwest by such Participant continue until the credits received by such Participant equal the total amount shown on such Participant's Billing Statement. The effect of this payment procedure is that amounts due Bonneville from the Participants (up to the Participants' obligations to Energy Northwest as shown on their Billing Statements) are required to be paid by the Participants to Energy Northwest rather than to Bonneville.

Project 1 and Project 3 have been terminated and, in accordance with the Net Billing Agreements for such Projects, the related Net Billing Agreements terminated except for those provisions that provide for the billing and payment of the costs of such Net Billed Project, including all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution to pay each year into the various funds for debt service and all other purposes, and the crediting of the proceeds of the disposition of the assets of such terminated Net Billed Project in reduction of such costs. The costs for each Net Billed Project after termination include all of Energy Northwest's accrued costs and liabilities resulting from Energy Northwest's ownership, construction, operation (including cost of fuel) and maintenance of and renewals and replacements to the terminated Project and all other Energy Northwest costs resulting from its ownership of such Project and the salvage, discontinuance, decommissioning and disposition or sale thereof and all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution to pay in each year into the various funds for debt service and all other purposes. The Columbia Net Billing Agreements have the same termination provision.

Since Project 1 and Project 3 have been terminated, Energy Northwest is required under each of the Project 1 Net Billing Agreements and Project 3 Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Project 1 Participant and Project 3 Participant of all costs associated with such termination. The monthly accounting statements are required to credit against such costs all amounts received by Energy Northwest from the disposition of assets of Project 1 and Project 3. The Project 1 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 1 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 1, whichever is later. The Project 3 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 3 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 3, whichever is later. If the monthly accounting statements show that such costs exceed such credits, each Project 1 Participant and Project 3 Participant, as the case may be, is required to pay its portion of such excess costs to Energy Northwest. The payments are to be made at times and in amounts sufficient to discharge on a current basis the Project 1 Participant's share or Project 3 Participant's share, as the case may be, of the amount which Energy Northwest is required to pay into the various funds provided in the related Electric Revenue Bond Resolution for debt service and all other purposes.

In the event of a termination of the Columbia Generating Station, Energy Northwest is required under the Columbia Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Columbia Participant of all costs associated with such termination in the manner discussed above for Project 1 and Project 3.

**Post Termination Agreements**

Bonneville and Energy Northwest have entered into Post Termination Agreements with respect to Projects 1 and 3, each dated June 14, 1994 (the "Post Termination Agreements"), which, among other things, facilitate the administration, budgeting and billing procedures with respect to such Projects. Nothing in the Post Termination Agreements impairs or prevents Energy Northwest from including in the monthly accounting statements with respect to each such Project all costs and obligations of Energy Northwest as discussed above.

**Assignment of Participant Shares**

If Bonneville determines that a Participant's payment obligations to Bonneville under its power sales and other contracts will not equal or exceed the Participant's payment obligations during a contract year under its Net Billing Agreement and, in the opinion of Bonneville and the Participant, such deficiency is expected to continue for a significant period, Bonneville is required under the related Net Billing Agreement to use its best efforts to assign such Participant's share of capability in the Net Billed Project (and the associated benefits and obligations) to other Participants in the Net Billed Project or to other Bonneville customers to the extent necessary to eliminate such Participant's net billing deficiency. The Net Billed Project capability so assigned would then be included by Bonneville under net billing arrangements with such other Participant or customer.

If Bonneville were unable to arrange for such assignments, the Participant would be required to make such assignment to other Participants pro rata. The other Participants would be obligated to accept such assignments to the extent required to eliminate such deficiency. Such mandatory assignments to any Participant may not exceed 25% of that Participant's original share of the Net Billed Project capability without the consent of that Participant. In addition, no such mandatory assignment may be made if it would cause the estimate of that Participant's obligation to Energy Northwest to exceed the estimate of the credits available to it from Bonneville, as estimated by Bonneville. Bonneville has made voluntary payments directly to Energy Northwest on behalf of Participants prior to reassigning their shares to eliminate net billing deficiencies. See "Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants."

The Net Billing Agreements provide that if reassignments cannot be made in amounts sufficient to bring into balance the respective dollar obligations of Bonneville and a Participant and an accumulated balance in favor of such Participant from a previous contract year is expected by Bonneville to be carried for an additional contract year, Bonneville is obligated to pay the balance. Any subsequent monthly net balances that exceed the amount of Bonneville's bill for that month will be paid to such Participant by Bonneville as cash deficiency payments, subject to the limitations described herein under Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund." The Participants are obligated to pay to Energy Northwest the amounts received from Bonneville within 30 days.

**Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants**

In 1979 and 1980, Bonneville and Energy Northwest entered into agreements with a large portion of the Participants (representing between roughly 70-80% of the capability of each Project, depending on the Project) relating to payments to Energy Northwest under the Net Billing Agreements. These agreements ("Voluntary Payment Agreements") provide that Bonneville, prior to making a reassignment of a Participant's share, may (but is not required to) pay directly to Energy Northwest, for the account of the Participant, the amount by which the Participant's obligation to Energy Northwest exceeds the billing credits allowed or estimated to be allowed to the Participant during the contract year. Under the Voluntary Payment Agreements, the related Participants agreed that they would not seek payment from Bonneville for any amounts so paid to Energy Northwest. In the case of Participants that have not signed Voluntary Payment Agreements, Bonneville has nonetheless made a number of similar voluntary payments to Energy Northwest on their behalf. When Bonneville does so it notifies the related Participants by letter that it has made such voluntary payments to Energy Northwest. See Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" for more information. Because of these payments, no reassignments of Participants' shares or deficiency payments by Bonneville to Participants have been necessary. These payments have also assisted in managing the cash flow requirements of Energy Northwest.

**Assignment Agreements**

Pursuant to the Assignment Agreements, Energy Northwest assigned to Bonneville any rights to the capability of any of the Net Billed Projects that Energy Northwest may obtain as a result of a reversion of a Participant's share of such capability to Energy Northwest or by any other means. For example, in the event that it were judicially determined that any Participant is not obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agreed to pay directly to Energy Northwest the amounts that would have been payable by the Participant under the Net Billing Agreements for such Project capability. For a summary of certain provisions of the Assignment Agreements, see Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

**Direct Pay Agreements**

Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project ("Direct Pay Agreements") pursuant to which, beginning May 2006, Bonneville pays at least monthly all costs for each Net Billed Project, including debt service on the Net Billed Bonds, directly to Energy Northwest. Each Participant pays directly to Bonneville all costs associated with its power sales and other contracts with Bonneville instead of making such payments to Energy Northwest. The Net Billing Agreements provide that Energy Northwest is to bill budgeted costs less amounts payable from sources other than the Net Billing Agreements to Participants. Direct payments received from Bonneville under the Direct Pay Agreements are considered a source other than the Net Billing Agreements and, therefore, the Net Billing Agreements were not amended. In the Direct Pay Agreements, Energy Northwest agrees to promptly bill each Participant its share of the costs of the respective Project under the Net Billing Agreements if Bonneville fails to make a payment when due under the Direct Pay Agreements. Although the amounts received by Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest. If the Direct Pay Agreements were terminated, Bonneville and Energy Northwest would return to the payment procedures described under "—Payment Procedures" above. See "—PLEDGE OF REVENUES AND PRIORITY" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

**Other Net Billing Obligations**

In addition to the net billing obligations in connection with the Net Billed Projects, Bonneville has net billing obligations to certain Participants in connection with that portion of the project capability associated with the 30% share of the terminated Trojan Nuclear Project owned by the City of Eugene, Oregon, acting by and through the Eugene Water and Electric Board. The credits and payments received by each Participant from Bonneville in each month under all of that Participant's agreements providing for net billing are required by the Net Billing Agreements to be allocated pro rata among all of the Participants' net billing obligations.

Bonneville is authorized to enter into additional contracts providing for net billing or similar credits. The Net Billing Agreements provide that Bonneville and each Participant shall not enter into any agreement providing for net billing if Bonneville estimates that, as a result of such agreement, the aggregate of its billings to such Participant will be less than 115% of Bonneville's net billing obligations to such Participant under all agreements between Bonneville and such Participant providing for net billing. Bonneville has no present plans to enter into new agreements with Participants requiring net billing to fund resource acquisitions; however, in fiscal year (October 1 through September 30) ("Bonneville Fiscal Year") 2013, Bonneville and four Preference Customers (each of which is a Net Billing Participant) 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 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 $340,000,000 in aggregate of prepayments from the participating customers. The offsetting prepayment credits are set at $2,550,000 per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028. While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use this form of Non-Federal Debt to meet some of its capital funding needs.

**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, including its cash payments to provide for that amount, if any, due under the Net Billing Agreements which is not paid from net billing credits. 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—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund."

Bonneville may make expenditures from the Bonneville Fund, which are required to 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, including making any cash payments required under the Net Billing Agreements.

Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Net Billed Projects, to the extent covered by net billing credits, can be met without regard to amounts in the Bonneville Fund.

Bonneville is required to make 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 (as defined in Appendix A—"THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (1) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (2) debt service on bonds issued by Bonneville and sold to the United States Treasury; (3) repayments of amounts appropriated to the Corps and the Bureau for costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (4) costs allocated to irrigation projects as are required by law to be recovered from power sales.

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 other than to the United States Treasury, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, 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 cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (1) through (4) 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 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 made all payments to the United States Treasury in full and on time since 1984, including in Bonneville Fiscal Year 2022.

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 and Trojan Nuclear 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 net billing cash payments and payments under the Direct Pay Agreements, and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury. The costs of the Net Billed Projects are currently covered through the Direct Pay Agreements rather than by net billing credits.

For further information, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Bonneville's Non-Federal Debt." For a discussion of certain direct payments by Bonneville for Federal System operations and maintenance, which payments would reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Direct Funding of Federal System Operations and Maintenance Expense."

Bonneville's obligation under the Net Billing Agreements for each Net Billed Project is to pay an amount equal to the costs of such Net Billed Project less any other funds which are required to be specified in the Annual Budget as payable from sources other than the payments to be made under such Net Billing Agreements. In the opinion of Bonneville's General Counsel, this provision would permit Bonneville to make payments on account of debt service on all Net Billed Bonds for a Net Billed Project directly to the applicable Bond Fund Trustee or Trustee. Such payment would be made only pursuant to an agreement with the applicable Bond Fund Trustee or Trustee requiring Bonneville to make such payment directly to the applicable Bond Fund Trustee or Trustee on or before the date such amounts would be required to be paid by Energy Northwest to the applicable Bond Fund Trustee or Trustee under the applicable Net Billed Resolution. Bonneville has no present intention of undertaking such actions. The effect of such an agreement would be to reduce the amount of costs included in the Annual Budget for the Net Billed Project to be paid under the Net Billing Agreements by the amount of the debt service payable directly by Bonneville to the applicable Bond Fund Trustee or Trustee.

For further information see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS."

## ENERGY NORTHWEST

### GENERAL

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington, was organized in January 1957 pursuant to the Act. Energy Northwest was formerly known as Washington Public Power Supply System. The name was officially changed to Energy Northwest on June 2, 1999. Energy Northwest has authority, among other things, to acquire, construct and operate plants, works and facilities for the generation of and transmission of electric power and energy and to issue bonds and other evidences of indebtedness for such purposes. Energy Northwest has the power of eminent domain, but is specifically precluded from the condemnation of any plants, works or facilities owned and operated by any city, public utility district or investor-owned utility. Energy Northwest is exempt from federal income tax and has no taxing authority.

Energy Northwest owns and operates Columbia and Packwood, which are currently in operation, and have current net design electric ratings of 1,174 MW and 27.5 MW, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, which has a maximum generating capacity of 95.9 MW. Energy Northwest had four nuclear electric generating projects that have been terminated: Projects 1, 3, 4 and 5. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "—PROJECT 1," "—PROJECT 3" and "—PROJECTS 4 AND 5."

Each of Energy Northwest's projects is treated and accounted for by Energy Northwest as a separate utility system, with the exception of Projects 4 and 5, which together comprised a single utility system. Under Washington law, a joint operating agency may create separate special funds for each of its utility systems and Energy Northwest has done so. The resolutions of Energy Northwest pursuant to which its various series of bonds are issued provide that the income, receipts and revenues of each utility system are pledged solely to the payment of obligations incurred in connection with that utility system. The financial statements of Energy Northwest Projects for the year ended June 30, 2022, included in this Official Statement as Appendix C, have been audited by Baker Tilly US, LLP, independent accountants, as stated in their report appearing therein.

### ENERGY NORTHWEST INDEBTEDNESS

The following table sets forth the principal amounts of revenue bonds and refunding revenue bonds issued by Energy Northwest and outstanding as of March 31, 2023. This table does not include information with respect to the Project 1 2020 Note, the Columbia 2020A/B Notes and the Project 3 2020 Note. See "INTRODUCTION."

**ENERGY NORTHWEST REVENUE BONDS**
**OUTSTANDING AS OF MARCH 31, 2023**

| REVENUE BONDS | PRINCIPAL AMOUNT |
|---|---|
| PROJECT 1: | |
| Electric Revenue Refunding Bonds | $ 792,710,000 |
| COLUMBIA: | |
| Electric Revenue and Refunding Bonds | $ 3,096,640,000 |
| PROJECT 3: | |
| Electric Revenue Refunding Bonds | $ 944,820,000 |
| TOTAL NET BILLED REVENUE BONDS | $ 4,834,170,000 |
| Nine Canyon Wind Project Revenue Bonds[(1)] | $ 42,220,000 |

(1) Bonneville is not a party to any agreements that secure payment of the Nine Canyon Wind Project Revenue Bonds.

Bonneville manages its overall debt portfolio, which includes both Bonneville's repayment obligations to the United States Treasury and debt that is secured by Bonneville's financial commitments, 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. See "THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS" in Appendix A.

Since 2001, Energy Northwest 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. These refundings are known as "Regional Cooperation Debt."

In September 2018, the Energy Northwest Executive Board adopted a motion supporting the extension of Regional Cooperation Debt through Energy Northwest's fiscal year (July 1 through June 30) 2030 ("Energy Northwest Fiscal Year"). The Energy Northwest Board must approve each series of Net Billed Bonds. Bonneville estimates that the aggregate potential principal amount of refinancing Net Billed Bonds that could be issued through Bonneville's Fiscal Year 2030 can be up to $2.9 billion. In 2022, Energy Northwest issued $294,630,000 of Electric Revenue Refunding Bonds under this second phase of Regional Cooperation Debt, and a portion of the Series 2023-A Bonds are Regional Cooperation Debt.

The current phase of Regional Cooperation Debt refinancings have 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.

Pursuant to the 2020A/B Amended and Restated Loan Agreement, the amount of the Project 1 2020 Note is not to exceed $12,000,000, the amount of the Columbia 2020A/B Notes is not to exceed $86,000,000, and the amount of the Project 3 2020 Note is not to exceed $12,000,000, with all maturing on April 30, 2024. Debt service on the Project 1 2020 Note is payable on a parity with the outstanding Project 1 Electric Revenue Bonds, including the Project 1 2023-A Bonds; the Columbia 2020A/B Notes are payable on parity with the outstanding Columbia Electric Revenue Bonds, including the Columbia 2023-A Bonds; and the Project 3 2020 Note is payable on a parity with the outstanding Project 3 Electric Revenue Bonds, including the Project 3 2023-A Bonds. As of March 1, 2023, Energy Northwest had borrowed $9,936,000 on the Project 1 Note, $26,795,000 on the Columbia 2020A/B Notes, and $10,798,000 on the Project 3 Note, all of which will be repaid with a portion of the proceeds of the Series 2023-A Bonds.

**ORGANIZATIONAL STRUCTURE**

Energy Northwest currently has a membership of 28, consisting of 23 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Public Utility District No. 1 of Douglas County joined Energy Northwest in October 2022. Any public utility district and any municipal entity within the State of Washington authorized to engage in the business of generating or distributing electricity may join Energy Northwest.

Energy Northwest has its principal office in Richland, Washington. The Board of Directors of Energy Northwest is comprised of 28 utility members, one from each of the member utilities. Pursuant to the Act, the powers and duties of the Board of Directors are limited to (1) final authority on any decision to acquire, construct, terminate or decommission any power plants, works and facilities, except that once such a final decision is made with respect to a nuclear power plant, the Executive Board has authority to make all subsequent decisions regarding such plant and any of its components; (2) the election and removal of, and establishment of salaries for, the five members of the Executive Board elected from among the members of the Board of Directors; and (3) the selection and appointment of three of the six members of the Executive Board who are outside directors. All other powers and duties of Energy Northwest, including but not limited to the authority to sell any power plant, works and facilities, are vested in the Executive Board.

The Act provides that five of the members of the Executive Board of Energy Northwest are elected by the Board of Directors from among its members and six are outside directors representative of policy makers in business, finance or science, or having expertise in the construction or management of facilities such as those owned by Energy Northwest. Three of these six outside directors are selected by the Board of Directors and three by the Governor of the State of Washington subject to confirmation by the Washington State Senate.

The five members of the Executive Board who are elected from among the Board of Directors serve for four-year terms and may be removed by a majority vote of the Board of Directors. The other members of the Executive Board serve for four-year terms and may be removed by the Governor of the State of Washington for incompetence, misconduct or malfeasance in office; provided, however, the three members appointed by the Governor may be removed without cause prior to their confirmation with the consent of the Washington State Senate. The Chief Executive Officer and other staff of Energy Northwest serve at the will of the Executive Board.

**EXECUTIVE BOARD**

Present Executive Board members are listed below.

| Name | Occupation | Term Expires |
|---|---|---|
| John Saven, Chair | Retired Utility Executive | June 2024 |
| Curt Knapp, Vice Chair | Public Utility District Commissioner | June 2026 |
| Bill Gordon, Secretary | Public Utility District Commissioner | June 2026 |
| James Moss, Assistant Secretary | Retired Executive | June 2022 |
| Arie Callaghan | Public Utility District Commissioner | June 2026 |
| Marc Daudon | Management Consultant | June 2022 |
| Janet Herrin | Retired Utility Executive | June 2025 |
| Johnny (Jack) Janda | Public Utility District Commissioner | June 2026 |
| Jim Malinowski | Public Utility District Commissioner | June 2026 |
| Bill Pitesa | Retired Nuclear Executive | June 2026 |
| Tim Sheldon | Retired Washington State Senator | June 2024 |

Two of the Gubernatorial Appointee positions expired in June 2022 (Marc Daudon and James Moss). The Washington State Governor is in the process of appointing new board members. The current Gubernatorial Appointees will continue to serve on the Executive Board until a new appointee is identified or the terms are extended.

**MANAGEMENT**

The following is a list of certain key senior staff of Energy Northwest.

| Name | Position | Nuclear Industry Experience |
|---|---|---|
| Robert E. Schuetz | Chief Executive Officer | 43 years |
| William G. Hettel | Executive Vice President/Chief Nuclear Officer | 41 years |
| Dave P. Brown | Site Vice President for Nuclear Operations | 30 years |
| Alex L. Javorik | Vice President for Engineering Projects | 42 years |
| Scott A. Vance | Vice President for Corporate Governance; General Counsel | 34 years |
| Cristina M. Reyff | Vice President for Corporate Finance, Chief Financial and Risk Officer | 15 years |
| Jeremy S. Hauger | Vice President for Engineering | 21 years |
| Greg V. Cullen | Vice President for Energy Services and Development | 29 years |
| Steve M. Lorence | General Manager for Corporate Support Services | 32 years |

**EMPLOYEES**

As of January 1, 2023, Energy Northwest employed 1,019 employees. Of these employees, 280 are members of the International Brotherhood of Electrical Workers ("IBEW"), 118 are members of the United Steel Workers ("USW") and five are members of the Hanford Atomic Metal Trades Council ("HAMTC") unions. The IBEW union members comprise the Administrative, Nuclear, Travelers and Plant bargaining groups; the USW union members constitute the Security Force bargaining group; and the HAMTC union members comprise part of the Standards Lab Instrument Specialists. The Plant and Administrative bargaining agreements are in place through 2023. The Nuclear, HAMTC and Travelers bargaining agreements are in place through 2024. The Nuclear Security Officer bargaining agreement is also in place through 2024. Energy Northwest considers labor relations to be satisfactory and uses third parties when differences come up between Energy Northwest and the respective union that cannot be resolved, to ensure effective closure.

**INVESTMENT POLICY**

Energy Northwest invests its funds in accordance with the authority provided by the Electric Revenue Bond Resolutions, and its investment policy covers all funds and investment activities under the direct authority of Energy Northwest. The investment policy has been reviewed and accredited by the Washington Public Treasurers Association since 2015, with the most recent recertification occurring in October 2021. The next expected recertification is expected to occur in October 2024.

Investment securities purchased consist generally of obligations of, or obligations the principal of and interest on which is unconditionally guaranteed by, the United States of America or other investment securities permitted by the related Net Billed Resolutions. The current investment policy does not permit the purchase of leveraged or derivative-based investments.

For further information on the types of investments in which Energy Northwest is permitted to invest its funds, see Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Investment of Funds (Section 508)."

**RETIREMENT PLANS AND OTHER POST-EMPLOYMENT BENEFITS**

Energy Northwest offers a 401(k) Deferred Compensation Plan, a 457 Deferred Compensation Plan, State of Washington (the "State") pension program and Other Post-Employment Benefits. For information on these plans including benefits, investment returns and sensitivity, see Notes 6 and 7 in the Audited Financial Statements of Energy Northwest Projects for the Year Ended June 30, 2022, included herein as Appendix C.

Energy Northwest participates in the State Public Employees Retirement System ("PERS"), which consists of defined benefit Plans 1 and 2 and a hybrid defined benefit/defined contribution Plan 3. PERS participants who joined the system by September 30, 1977 are Plan 1 members. Members now have the option of choosing Plan 2 or Plan 3.

State law requires systematic actuarial funding to finance the retirement plans. Actuarial calculations to determine employer and employee contributions are prepared by the Office of the State Actuary ("OSA"), a nonpartisan legislative agency charged with advising the legislature of the State (the "State Legislature") and State Governor on pension benefits and funding policy. Contributions by both employees and employers are based on gross wages. State law requires systematic actuarial funding to finance the retirement plans. To calculate employer and employee contribution rates necessary to pre-fund the plans' benefits, OSA uses actuarial cost and asset valuation methods selected by the State Legislature as well as economic and demographic assumptions. The State Legislature adopted the following economic assumptions for contribution rates beginning July 1, 2022: (1) 7.0% per annum rate of investment return (as stated in the State Department of Retirement Systems ("DRS") Annual Comprehensive Financial Report for the year ended June 30, 2022); (2) general salary increases of 3.25% per annum; and (3) 3.00% rate of Consumer Price Index increase. The assumed long-term investment return used as the discount rate for determining the liabilities for each plan is 7.0% for the calculation of contribution rates for the 2021-23 Biennium. The long-term investment return assumption is used as the discount rate for determining the liabilities for a plan. Most retirement funds are invested by the Washington State Investment Board, a 15-member board created by the State Legislature. The current contribution rates of employees and employers for PERS are 10.39% for employers and for employees 6.00% for PERS Plan 1, 6.36% for PERS Plan 2 and vary between 5.0% to 15.0% for PERS Plan 3.

All DRS retirement plans are funded by a combination of funding sources: (1) contributions from the State for certain plans; (2) contributions from employers (including the State as employer and Energy Northwest and other governmental employers); (3) contributions from employees; and (4) investment returns.

Pension costs for Energy Northwest employees are calculated and allocated to each Energy Northwest business unit based on direct labor dollars. Required contributions in Energy Northwest Fiscal Year 2022 was $16,038,000. About 93% of the required contributions to the PERS plans described above were paid by Columbia. Required contributions in Energy Northwest Fiscal Year 2021 were $18,699,000.

The State Actuary's actuarial valuation, using the Entry Age Normal ("EAN") cost method, for PERS Plan 1 and PERS Plans 2 and 3 as of June 30, 2021, showed a 71% funded ratio (unfunded liability of $3.303 billion) and an 95% funded ratio (unfunded liability of $2.588 billion), respectively. Using the EAN cost method, the State Actuary's actuarial valuation for PERS Plan 1 and PERS Plans 2 and 3 as of June 30, 2020, showed a 69% and 98% funded ratio, respectively.

While Energy Northwest's contributions represent its full current liability under the DRS systems, any unfunded pension benefit obligations could be reflected in future years as higher contribution rates. It is expected that the contribution rates for employees and employers in PERS Plans 2 and 3 will increase in the coming years. The OSA website (which is not incorporated into this Official Statement by reference) includes information regarding the values, funding levels and investments of these retirement plans.

The Governmental Accounting Standards Board ("GASB") has implemented pension regulations that require employers, including Energy Northwest, to report their pension liabilities on a generally accepted accounting principles ("GAAP") basis rather than a funding basis. Beginning with its 2015 financial statements, Energy Northwest reported its proportionate share of the net plan asset or liability for each pension plan in which Energy Northwest employees participate. The liability is based on the actuarial present value of projected benefit payments to periods of employee service, a discount rate that considers the availability of plan assets and recognition of projected investment earnings. The DRS will determine each participating employers' proportionate share of the plan liability and OSA will determine each plan's accounting valuation. The GASB rules impact accounting for pensions and not the funding status of the plans calculated by OSA or pension contribution rates that are set based on statutory assumptions. See Note 6 in the financial statements of Energy Northwest Projects for the year ended June 30, 2022, included as Appendix C herein, for Energy Northwest's share of net liability and expenses.

Energy Northwest has two liabilities related to other post-employment benefits ("OPEB"). The first is related to grandfathered life insurance for retirees and has been determined to be immaterial to the financial statements as a whole for reporting. The second is an implicit benefit received from employees receiving medical insurance through the State Department of Retirement Systems following retirement. Energy Northwest Fiscal Year 2022 total liability was $29.6 million. Like the liability related to the PERS retirement plan Energy Northwest is not directly responsible for the recovery of this cost nor does it make any direct payments for this benefit to retirees.

## THE COLUMBIA GENERATING STATION

### Description

The Columbia Generating Station is an operating nuclear electric generating station located about 160 miles southeast of Seattle, Washington, near Richland, Washington on the DOE's Hanford Reservation. The site has been leased from DOE and the lease is scheduled to terminate on January 1, 2052.

In May 2012, the Nuclear Regulatory Commission ("NRC") approved Columbia's 40-year operating license for an additional 20-years, extending operation of Columbia through 2043. See "Permits and Licenses."

Columbia commenced commercial operation in 1984 and has a current net design electric rating of 1,174 MW. Columbia consists of a General Electric Company-designed boiling water reactor and nuclear steam supply system, a Westinghouse turbine-generator and the necessary transformer, switching and transmission facilities to deliver the output to the transmission facilities of the Federal System located in the vicinity of Columbia. Bonneville has acquired the entire capability of Columbia under the Columbia Net Billing Agreements. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS."

Columbia consists of the following structures: the reactor building, the radioactive waste building, the turbine-generator building, the diesel generator building, the service building, six mechanical-draft evaporative cooling towers, the circulating water pumphouse and the river makeup water pumphouse. Makeup water to replace evaporative losses is obtained from the Columbia River by means of three makeup water pumps. Emergency power is supplied to Columbia by diesel generators sized to sustain all essential plant loads without the need for outside power sources. Columbia also includes the Independent Spent Fuel Storage

Installation facility. For additional information concerning the Independent Spent Fuel Storage Installation facility, see "Nuclear Fuel" below.

Columbia also includes the plant engineering center and other office and support facilities located adjacent to the main plant, the plant support facility located one mile southwest of the main plant and various administrative service buildings located in Richland, Washington, approximately ten miles from the site.

Low-level radioactive waste generated at Columbia is disposed of at a commercial facility located on the Hanford Reservation.

**Management Discussion of Operations**

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has a maintenance, operating, fuel and capital budget for Columbia of $689.5 million for the 2023 Energy Northwest Fiscal Year.

The cost of production, using industry standard methodology (such cost calculation methodology includes general, administration and capital costs, but excludes debt service, taxes, depreciation, and decommissioning costs), of Columbia electricity is budgeted at $50.59 per megawatt-hour ("MWh") for the Energy Northwest Fiscal Year 2023. This budgeted cost is higher than the $36.29 per MWh for the Energy Northwest Amended Fiscal Year 2022 Budget because Fiscal Year 2023 includes a refueling and maintenance outage.

Energy Northwest continues to focus on plant reliability, availability and increasing gross plant capacity as the primary factors to reduce the cost of power. Initiatives to reduce losses of generation, such as reducing outage length and reducing or eliminating the occurrences of forced outages, are continually being evaluated and implemented.

**Recent Developments**

With a 100% carbon-free energy portfolio, Energy Northwest is positioned to help lead Washington state in developing new clean energy generating resources and transportation electrification projects. The 2019 passage of the Clean Energy Transformation Act provides public power with the opportunity to help Washington meet its climate goals while maintaining a reliable and affordable electric grid.

The Columbia Generating Station was named a top performing plant by its industry peers in 2022. Columbia produced a record amount of electricity in 2022 — more than 9.8 million megawatt-hours. It is the highest output for any calendar or fiscal year in the station's 38-year history. In addition to a new generation record, Columbia's capacity factor in 2022 was 99.4%, meaning it was producing power almost the entire year. Nuclear energy has the highest capacity factor of any energy source.

Energy Northwest estimates Columbia's production cost of power will average 3.14 cents per kilowatt-hour during its 2022-2023 fuel cycle, down from 5.2 cents, adjusted for inflation, nearly 10 years ago.

In 2022, Energy Northwest received first-place safety awards from the Northwest Public Power Association and the American Public Power Association. For the seventh year in a row, Energy Northwest was designated a military friendly employer, recognizing its commitment to and programs for veterans and their families.

Energy Northwest commissioned Bisconti Research in June 2022 to conduct State-wide polling in Washington to gauge the public's view of nuclear energy. The survey found 87% view nuclear energy as important for meeting the nation's future electricity needs; 82% see nuclear energy as important for meeting Washington State's future electricity needs; and 73% favor the use of nuclear energy as one of the ways to provide electricity in Washington.

Energy Northwest remains committed to the development and siting of an advanced reactor project near Columbia this decade. Energy Northwest has received considerable project interest from both utility and industrial customers – with a fast-approaching need for new sources of carbon-free energy. The Northwest's clean energy goals and mandates are catalyzing a transformation of the region's energy infrastructure and X-energy's advanced reactor technology could be an ideal addition to Energy Northwest's portfolio of carbon-free resources, providing numerous benefits to the rapidly decarbonizing electric grid.

In the transportation sector, Energy Northwest and partners installed direct current fast-charging stations in central and eastern Washington to alleviate the "charging gap" or long distances between charging stations that made cross-state electric vehicle travel difficult. See "Energy Services and Development."

The recent passage of the Inflation Reduction Act (the "IRA") and the Infrastructure Investment and Jobs Act (the "IIJA") allows not-for-profit public power utilities like Energy Northwest to directly receive federal incentive payments for a variety of generation and infrastructure projects. Energy Northwest has established an internal team to research and analyze the potential impacts of the IRA and IIJA pending the issuance of regulatory guidance on the implementation of these provisions. No assurance can be given as to the potential benefits of the IRA or IIJA to Energy Northwest.

In May 2023, Energy Northwest will take Columbia offline for about 40 days for its 26th refueling outage. During the biennial outage, Energy Northwest will replace a third of the fuel in the reactor core and perform important maintenance on equipment to maintain and improve Columbia's generation efficiency and reliability.

**COVID-19 Pandemic**

To date no material impacts have occurred to the operations of Energy Northwest's generating facilities, including Columbia Generating Station, as a result of the COVID-19 Pandemic. Energy Northwest consistently implemented company-wide policies to mitigate the impacts of the COVID-19 Pandemic on its operations. Energy Northwest continues to monitor COVID-19 Pandemic conditions, laws, and regulations to prioritize the health and safety of the public, employees, and operations. Energy Northwest policies require all employees to self-screen for COVID-19 symptoms and exposures prior to reporting to work, and comply with applicable laws and regulations. Energy Northwest cannot predict how the COVID-19 Pandemic may progress, nor future impacts on Energy Northwest or Bonneville.

The COVID-19 Pandemic did not impact the overall budget for Energy Northwest's Fiscal Years 2020 and 2022. For Energy Northwest's Fiscal Year 2021, $2,091,500 was spent for all maintenance outage related costs, supplemental labor support, and non-labor related costs associated with the COVID-19 Pandemic. Currently, there is no budget set aside for COVID-19 Pandemic impacts for Energy Northwest's Fiscal Year 2023.

**Operating Performance**

Columbia received an operating license in December 1983, commenced commercial operation in December 1984, and has been in operation since that time. Since commencing commercial operation, Columbia has operated at a cumulative capacity factor of 77.8% and has generated 287,853,071 MWh (net of station use) of electric power through January 2023. In the ten Energy Northwest Fiscal Years ending June 30, 2022, however, the cumulative capacity factor was 91.2%.

Successful implementation of employee performance enhancement initiatives at Columbia has contributed to significant positive results in plant performance. The generation for Energy Northwest Fiscal Year 2022 was 9,990 GWh, which included economic dispatch and a refueling outage. Columbia produced 8,842 GWh of electricity in Energy Northwest Fiscal Year 2021. The Energy Northwest Fiscal Year 2022 generation increase of 13.0% was because Energy Northwest Fiscal Year 2022 was the highest fiscal year generation on record for Columbia when including economic dispatch granted by Bonneville for grid reliability and supply during the Columbia River's high spring river runoff, and Energy Northwest's Fiscal Year 2021 included a refueling outage.

**Annual Costs**

Annual costs for Columbia are derived from the audited financial statements for Energy Northwest Fiscal Years ended June 30, 2021 and 2022 and are shown below. The information is developed on a cost basis with depreciation calculated on the straight-line method by major components based on expected useful life.

**Statement of Operations**[(1)]
(Dollars in Thousands)

| Cost Category | Energy Northwest Fiscal Year 2021 | Energy Northwest Fiscal Year 2022 |
|---|---|---|
| Operations, Maintenance and Overhead | $250,923 | $171,191 |
| Nuclear Fuel | 55,648 | 60,270 |
| Generation Taxes | 4,797 | 5,491 |
| Decommissioning | 25,875 | 29,155 |
| Depreciation and Amortization | 87,735 | 95,660 |
| Investment Income | (465) | 87 |
| Interest Expense and Discount Amortization | 118,551 | 113,359 |
| DOE Settlement | (8,330) | (21,137) |
| Capital Contributions | (1,272) | (11) |
| Other Expense/(Revenue) | (5,723) | (29,052) |
| **Total Costs** | $527,739 | $425,013 |
| Net Generation (GWhs) | 8,842 | 9,990 |

(1) Dollar amounts derived from audited 2021 and 2022 Energy Northwest financial statements.

**Capital Improvements**

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. Prior to 2003, these additional capital expenditures at Columbia were funded through the Columbia Net Billing Agreements, without borrowings by Energy Northwest. Since 2003, Energy Northwest has funded some or all of its additional capital expenditures at Columbia through the issuance of Columbia Electric Revenue Bonds.

In Energy Northwest Fiscal Year 2022, Energy Northwest spent approximately $109.1 million on capital improvements at Columbia. Energy Northwest expects to spend approximately $136.1 million in Energy Northwest Fiscal Year 2023. The capital improvements at Columbia are expected to include plant and facility modifications, information technology improvements, and replacement of various pieces of equipment.

The following table shows the expected capital improvements at Columbia through Energy Northwest's Fiscal Year 2033, most of which are expected to be financed with Columbia Electric Revenue Bonds.

**Expected Capital Improvements**
(As of March 23, 2023)
(Dollars in Thousands)

| Energy Northwest Fiscal Year | Total Capital |
|---|---|
| 2023 | $136,135 |
| 2024 | 106,046* |
| 2025 | 213,320* |
| 2026 | 149,014* |
| 2027 | 139,445 |
| 2028 | 84,289 |
| 2029 | 153,447 |
| 2030 | 118,927 |
| 2031 | 240,785 |
| 2032 | 91,053 |
| 2033 | 160,336 |

* Extended power uprate related funding by fiscal year is expected to be around $9,580,000 in Energy Northwest Fiscal Year 2024, $9,978,000 in Energy Northwest Fiscal Year 2025 and $35,199,000 in Energy Northwest Fiscal Year 2026.

Certain of these capital expenditures are expected to be funded or reimbursed by amounts received by Energy Northwest from the Department of Energy pursuant to settlements for breach of contract actions against the United States of America for its failure to dispose of spent nuclear fuel and high-level radioactive waste for the periods from July 1, 2015, through at least June 30, 2022. See "—NET BILLED PROJECTS LITIGATION AND CLAIMS."

Energy Northwest is evaluating the feasibility of an extended power uprate ("EPU") initiative at Columbia with a current target implementation as early as 2031. Except for Energy Northwest Fiscal Years 2024 through 2026, total capital amounts listed in the table above exclude any capital related to EPU. The projected capital spending related to EPU for Energy Northwest Fiscal Years 2024 through 2026 are noted in the table above. Preliminary studies indicate there would be approximately $550 million of additional capital associated with Energy Northwest Fiscal Years 2027 and beyond, for a 2031 uprate implementation; however, this has not been fully evaluated or approved. Additionally, required funding amounts related to an uprate may shift between years to accomplish EPU in 2031. If implemented, EPU could increase Columbia's generating capacity by approximately 10-15% over its net design electric rating.

**Nuclear Regulatory Commission Actions**

The NRC is a Federal agency that regulates the design, construction, licensing and operation of nuclear power plants. Once a plant is licensed, one of the major activities of the NRC is the inspection of plant management and operation. The NRC develops policies and administers programs for inspecting licensees to ascertain whether they are complying with NRC regulations, rules, orders and license provisions. The NRC has the authority to suspend, revoke or modify the operating license of commercial nuclear plants to correct deficiencies.

Energy Northwest's activities related to operation and support of Columbia, like those of other licensed nuclear plant operators, are periodically inspected by the NRC. In addition, the NRC normally maintains two on-site resident inspectors who monitor plant activities on a day-to-day basis.

In addition to the day-to-day resident inspector activities, the NRC assesses the performance of nuclear plant operators, including Columbia, by a process known as the Reactor Oversight Process (the "ROP"). The ROP is built upon a framework directly linked to the NRC's mission to protect public health and safety. The framework includes seven cornerstones of safety. Within each cornerstone, a broad sample of information on which to assess plant operator performance in risk-significant areas is gathered. The information is collected from plant performance indicator data submitted by the plant operator and from NRC risk-informed baseline inspections.

The ROP calls for focusing inspections on activities where the potential risks are greater, applying greater regulatory attention to facilities with performance problems and reducing regulatory attention to facilities that perform well, using objective measurements of the performance of nuclear power plants whenever possible, giving the nuclear industry and the public timely and understandable assessments of plant performance, avoiding unnecessary regulatory burdens of nuclear facilities and responding to violations of regulations in a predictable and consistent manner that reflects the safety impact of the violations.

To monitor these seven cornerstones, the NRC assigns colors of Green, White, Yellow or Red to specific performance indicators and inspection findings. For performance indicators, a Green coding indicates performance within an expected performance level in which the related cornerstone objectives are met; White coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; Yellow coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin; and Red coding indicates a significant reduction in safety margin in the area measured by that performance indicator.

For inspection findings, Green findings are indicative of issues that, while they may not be desirable, represent very low safety or security significance. White findings indicate issues that are of low to moderate significance. Yellow findings are issues that are of substantial safety significance. Red findings represent issues that are of high safety significance with a significant reduction in safety margin. On January 13, 2022, the NRC notified Energy Northwest of a preliminary White finding due to failures to implement and follow written procedures for radiation protection, which resulted in uptakes of radioactive materials to two workers resulting in doses of greater than 700 millirem committed effective dose equivalent. No violation of administrative or federal limits occurred. Energy Northwest discussed the uptake event with the NRC staff on March 1, 2022 to provide additional information supporting Energy Northwest's perspective that the finding is of very low safety significance, or a Green finding. On April 14, 2022, the NRC informed Energy Northwest that although they committed to provide a final decision within 45 days (from March 1, 2022), they received new information that requires additional review and the final decision is on hold, pending review of the new information. In March 2023, the NRC informed Energy Northwest that active work is still ongoing to finish formal characterization of the uptake event. No specific timeline was provided for when Energy Northwest will be provided the results. Prior to this preliminary finding, there were no greater than Green findings at Columbia since a White finding for shipping radioactive material in November 2016 in the incorrect container on public roadways that did not comply with Department of Transportation regulations.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary that can be found on the NRC's website (https://www.nrc.gov/reactors/operating/oversight/actionmatrix-summary.html). The Safeguards (Physical Protection) cornerstone performance indicators and inspection findings are not integrated into the Action Matrix Summary. The Action Matrix Summary reflects overall plant performance, which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance columns.

Best performing plants are included in the Licensee Response Column where routine (baseline) inspection and staff interaction is the norm. The next level of performance is the Regulatory Response Column, which includes plants that have no more than two White inputs in different strategic performance areas. Plants in this column are subject to NRC inspection follow-up of utility corrective actions. There are three remaining Response Columns, including the Unacceptable Performance Column, which includes plants that are not permitted to operate.

As of January 25, 2023, 87 plants, including Columbia, were in the NRC's Regulatory Oversight Process Summary Licensee Response Column, with six plants in the Regulatory Response Column, and no plants in the Multiple/Repetitive Degraded Cornerstone Column, the Degraded Cornerstone Column or the Unacceptable Performance Column.

**World Association of Nuclear Operators**

Energy Northwest is a member of the World Association of Nuclear Operators ("WANO"), a nonprofit organization that works to unite every company and country with an operating commercial nuclear power plant to achieve the highest possible standards of nuclear safety. WANO works directly with its members to help operators communicate effectively and share information openly. WANO is based in London, England, and has regional centers in Atlanta, Moscow, Paris and Tokyo, and its policies and programs are established on a global level. One of these programs is the peer review, which helps members compare their operational performance against standards of excellence through an in-depth, objective review of operations by an independent team. WANO expects to have a peer review every four years at U.S. nuclear plants. The WANO Corporate Evaluation of Energy Northwest occurred in November 2017, and the report included two areas for improvement and two strengths. Energy Northwest continually reviews its performance according to these areas and addresses any areas for improvement. The next WANO Corporate Evaluation is expected to occur in fourth quarter of 2023. Additionally, WANO performed a peer review of Columbia's station performance in November 2022. Several strengths and a few areas for improvement were noted by the evaluation team and initiatives were put in place for enhancing station performance.

**Institute of Nuclear Power Operations**

The United States nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. The INPO mission is to promote the highest levels of safety and reliability in the operation of nuclear power plants. All United States utilities that operate commercial nuclear power plants, including Energy Northwest, are INPO members. INPO conducts continuum site visits of all United States plants, including Columbia, approximately every four years. WANO peer evaluations occur every four years and alternate with continuum site visits. Additionally, INPO continuum site visits serve as a WANO follow-up peer review. In November 2022, a WANO peer evaluation was conducted with a few areas for improvement and strengths noted. The next INPO continuum site visit is targeted for fall 2024. INPO also performs continuous performance monitoring. Key station personnel work directly with their INPO point of contact as part of this continuous performance monitoring to ensure station performance is clearly understood and any gaps to excellence are addressed in a timely manner.

**Permits and Licenses**

Energy Northwest has obtained all permits and licenses required to operate Columbia, including an NRC operating license which originally expired in 2023. In May 2012, the NRC approved Columbia's license for another 20 years, which will extend operation of Columbia through 2043. See "Nuclear Regulatory Commission Actions" above for a discussion of NRC inspection activities related to Columbia.

A site certification agreement for Columbia was executed with the State of Washington in May 1972. The site certification requires Energy Northwest, among other things, to monitor the environmental effects of plant construction and plant operation, comply with standards set for the consumption and discharge of water and for discharges to the air, and develop an effective emergency plan. The State's Energy Facility Site Evaluation Council ("EFSEC") has also issued a National Pollutant Discharge Elimination System ("NPDES") permit and the necessary Certificate of Water Right. The Certificate of Water Right expires when use ceases. Columbia's NPDES permit is in the process of being renewed. Columbia's NPDES permit has been administratively extended and remains in effect until an updated NPDES permit is issued by EFSEC. The Washington State Department of Natural Resources has entered into a lease with Energy Northwest for that portion of the bed of the Columbia River which encompasses the plant intake and discharge facilities. The Corps has issued a permit for construction and maintenance of the completed river facilities.

In April 2018, Energy Northwest applied for a radioactive air emissions license ("RAEL") from the State through EFSEC and the State's Department of Health ("DOH"). The State regulates radioactive air emissions under Washington Administrative Code, Chapter 246-247. In November 2020, Columbia received a draft RAEL and Energy Northwest submitted comments to such draft. Energy Northwest is awaiting a response to its comments and is continuing to work with EFSEC and DOH to address comments.

**Depleted Uranium Enrichment Program**

In May 2012, the Executive Board of Energy Northwest approved participation in a depleted uranium enrichment program (the "Program") to provide fuel for Columbia, and to ensure an adequate and secure supply of fuel, to minimize exposure to fluctuations in market prices and to procure the fuel at a significant savings. Energy Northwest issued Columbia Electric Revenue Bonds in August 2012 to finance a portion of the cost of the Program. Under the Program, the U.S. Department of Energy ("DOE") provided approximately 9,082 metric tons of depleted uranium hexafluoride ("Uranium Tailings") at no cost to Energy Northwest. The Uranium Tailings were physically transferred from DOE ownership to Energy Northwest ownership at the Paducah Gaseous Diffusion Plant ("PGDP") in Paducah, Kentucky, where the Uranium Tailings were enriched to a level necessary for fabrication into commercial nuclear fuel (the Uranium Tailings as so enriched, the "Enriched Uranium").

Although Energy Northwest could use the entire amount of Enriched Uranium for Columbia's fuel needs through 2038, in order to improve the economic value of the Program and minimize risks, Energy Northwest agreed to sell a portion of the Enriched Uranium and the value of separative work units (which is the process by which the assay or weight percent of the uranium-235 isotope is increased) to the Tennessee Valley Authority ("TVA") with deliveries that began in May 2015 with the final delivery made in August 2022 bringing the Program to completion. Energy Northwest received all payments due in accordance with the TVA agreement.

**Nuclear Fuel**

The supply of nuclear fuel assemblies requires four basic activities prior to insertion of the fuel assemblies into a nuclear reactor. These activities are acquisition of uranium concentrates; conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and conversion of the Enriched Uranium to uranium oxide pellets, which are fabricated into finished fuel assemblies.

Fabrication services through 2027 reloads are provided pursuant to a contract with Global Nuclear Fuel – Americas, LLC. Columbia operates on a 24-month fuel cycle. A 24-month fuel cycle eliminates the need for refueling outages every year and results in increased average generation. To meet the enriched uranium requirements for the reload fuel assemblies, Energy Northwest purchases uranium in various forms and holds them in inventory until needed for fuel fabrication. As discussed in the previous subsection, Energy Northwest approved the Program, which is expected to provide enough natural uranium to meet Columbia's requirements through 2028.

As a result of the low market conditions and overall cost of borrowing compared to significantly higher prices forecasted in the future, Energy Northwest issued a request for proposal in 2020 for both near-term and long-term supplies. Energy Northwest made the decision to cover the Energy Northwest Fiscal Years 2027-2030 uranium and enrichment purchases with a long-term supply contact with Orano, a global nuclear fuel cycle company. In addition, Energy Northwest elected to purchase 66,000 KgU of 4.95% enriched uranium from Urenco, a British-German-Dutch nuclear fuel consortium operating several uranium enrichment plants in Germany, the Netherlands, the United States and the United Kingdom, which was delivered in November 2020 and placed into inventory for a total cost of $98,010,000. These purchases combined with existing inventories and contracts provide enough uranium and enrichment to meet the requirements of Columbia through 2037. The costs of acquiring fuel for the Columbia Generating Station was reimbursed with Columbia Electric Revenue Bonds issued in 2021.

Sanctions against Russia are not expected to adversely impact Energy Northwest, given all of Energy Northwest's long-term fuel storage and supply contracts are with non-Russian suppliers. Energy Northwest has existing U.S. based inventory and supply contracts to fulfill the Columbia reload requirements through the 2029 refueling. In addition, there are inventories in storage, as well as a longer-term supply contract with western European suppliers to meet the reload requirements through the 2035 refueling. Energy Northwest is well insulated against future uranium market price increases and/or supply disruptions that could arise from prolonged U.S. sanctions on imports of uranium from Russia into the U.S. See "—RISK MANAGEMENT—Russian Energy and Sanctions."

Energy Northwest has a contract with DOE that requires DOE to accept title and dispose of spent nuclear fuel. For this future service, Energy Northwest has paid a quarterly fee based on about one dollar per megawatt-hour of net electricity generated and sold from Columbia; however, the District of Columbia Court of Appeals ruled that the DOE had no grounds to collect the waste fees unless the Yucca Mountain project is restarted or Congress passes an alternative disposal plan. DOE ceased collecting the disposal fee from Energy Northwest effective May 16, 2014. To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating proposed sites for a repository. Although courts ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. Once DOE begins to accept spent fuel, it will accept the oldest spent fuel first, on a national basis. Because Columbia is a relatively young plant, DOE does not plan to accept any spent fuel from Columbia during the first 10 years of repository operation.

Energy Northwest's Independent Spent Fuel Storage Installation ("ISFSI") at Columbia is a temporary dry cask storage facility intended to store spent nuclear reactor fuel in NRC-approved dry storage casks until the DOE completes its plan for a national repository. The ISFSI consists of two concrete pads storing a total of 36 casks and one additional pad with the capacity of 18 casks. The last ISFSI campaign, which began in March 2022, was completed in May 2022 for an additional nine casks. In order to accommodate spent fuel to be generated through the end of the plant's operating license period of December 20, 2043, Energy Northwest is planning the ISFSI facility expansion to store an additional 72 casks. The final phase of the ISFSI pad expansion project will be completed in Energy Northwest Fiscal Years 2021-2024 and will be commissioned in 2025. The four additional pads will have capacities of 18 casks each. Energy Northwest previously financed a portion of the costs needed for the construction of the existing ISFSI pads.

No additional issues are anticipated with the ISFSI expansion project. However, the NRC is in the process of developing additional security rulemaking which may potentially impose additional requirements beyond currently planned security controls. The extent of those additional requirements or when they will be imposed on Columbia are not known at this time but are not anticipated to become effective within the next two or three years.

**Decommissioning and Site Restoration**

GASB implemented an asset retirement obligation ("ARO") standard with Statement No. 83 and has a required implementation date for periods beginning after June 30, 2018. This statement requires that recognition occurs when the liability is both incurred and reasonably estimable. The ARO is to be measured based on the best estimate of the current value of outlays expected to be incurred and that the ARO be measured at the amount of the corresponding liability upon initial measurement. Statement No. 83 requires the ARO to be reviewed annually and adjusted for inflation or deflation. In addition the statement requires a yearly evaluation of relevant factors that could materially change the estimated asset retirement outlays. Energy Northwest implemented GASB Statement No. 83, effective with the Energy Northwest Fiscal Year 2019 annual reporting. Energy Northwest completed an ARO cost estimate study of Columbia and ISFSI, which was a joint effort between Energy Northwest and Bonneville.

The NRC has defined decommissioning as actions taken which result in the release of the property for unrestricted use and termination of the nuclear power plant operating license. Currently, the nuclear industry recognizes three alternative methods (decontamination ("DECON"), safe storage ("Safstor") and entombment) to decommission a nuclear power plant, though entombment is no longer part of Energy Northwest's current estimates. A joint decision between Energy Northwest and Bonneville was made to adopt the DECON method for accounting purposes. DECON entails the facility and site containing radioactive contaminants are removed or lowered to levels that permit unregulated use shortly after cessation of operations. Safstor entails placing and maintaining the nuclear facility in a condition that allows it to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use.

The Columbia study using DECON as the scenario has an estimated decommissioning activity completion date of June 2097. In Energy Northwest's Fiscal Year 2022, $28.9 million of amortization expense was recognized and the index adjustment for Energy Northwest's Fiscal Year 2022 was $132.6 million resulting in the overall increase in deferred outflow of $103.7 million. The index adjustment increased the estimated liability as of June 30, 2022 from $1.54 billion to $1.67 billion.

Each year the ARO will be evaluated to determine if there are any material changes in timing or costs. There were no material changes in timing or costs that would impact the ARO for Energy Northwest's Fiscal Year 2022. In spring 2023, there will be an interim review of timing and costs of the ARO for Energy Northwest's Fiscal Year 2023.

At the time of termination of Columbia and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the expected completion date of Fiscal Year 2097. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment, a gain or loss on the ARO will be recorded for the difference.

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Annual payments to a fund established pursuant to this plan began in 2003 and were originally held by Energy Northwest. These payments were scheduled to occur annually through 2044. The Columbia cost study completed in February 2019 included the ISFSI. ISFSI decommissioning is projected to be completed in a five-month period in 2097 under the DECON scenario and was estimated at $7.5 million (in 2019 dollars). As of June 30, 2022, the estimated ISFSI liability is $8.6 million. In March 2021, Energy Northwest transferred ownership of the ISFSI trust fund to Bonneville, in order for Bonneville to manage the ISFSI fund along with the primary Columbia decommissioning and site restoration trust funds.

For more details regarding the Columbia decommissioning and restoration trust funds held by Bonneville, see Appendix B-1 to the Official Statement (Note 6 to the Fiscal Year 2022 Audited Financial Statements).

**PACKWOOD LAKE HYDROELECTRIC PROJECT**

Energy Northwest owns and operates the Packwood Lake Hydroelectric Project ("Packwood"), a hydroelectric generating facility which can generate 26 MW of electricity. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles southeast of Seattle, Washington. Packwood was granted a Federal Energy Regulatory Commission (FERC) operating license on March 1, 1960 and began commercial operation in June 1964. FERC approved a 40-year operating license for Packwood, effective October 1, 2018.

In Energy Northwest Fiscal Year 2022, production at Packwood totaled 96.12 net GWh, an increase of approximately 8.5% from the previous year primarily due to Energy Northwest Fiscal Year 2021 being the 21st lowest generation year on record. Energy Northwest Fiscal Year 2022 generation exceeded the last five-year average net generation of 86.37 GWh, due to efficient management of lake level resources and was above the life to date average per year of 93.90 GWh. Packwood's average availability during the last 15 years has been 98.3%, and has produced 5,483,456 net MWh since commercial operation began. Packwood is a separate system of Energy Northwest and the Packwood participants are required to pay their share of the annual budget of the project, whether the project is producing power or capable of producing power.

**NINE CANYON WIND PROJECT**

Energy Northwest owns and operates the Nine Canyon Wind Project, a wind energy project, which is capable of generating 95.9 MW of electricity. The project is located on leased land near Kennewick, Washington. The 49 wind turbines of the Nine Canyon Wind Project have a power generating capacity of 1.3 MW each and there are an additional 14 wind turbines with 2.3 MW of power generating capacity each. The turbines were manufactured by Siemens Gamesa Renewable Energy, Inc. (previously BONUS Energy A/S). The project is a separate system of Energy Northwest and the bonds are secured by, and payable solely from, the revenues derived by Energy Northwest under power purchase agreements executed with public utility purchasers. The purchasers are required to pay their share of the annual budget of the project, which includes debt service on the related bonds, whether or not the project is operating or capable of operating.

Power costs for the project billed to the purchasers averaged 6.65 cents per kilowatt hour during Energy Northwest Fiscal Year 2022. The cost of power fluctuates year to year depending on various factors such as wind conditions and unplanned maintenance. In Energy Northwest Fiscal Year 2022, Nine Canyon produced 238.62 net GWh of electricity, compared to 236.32 net GWh in Energy Northwest Fiscal Year 2021. Generation for Energy Northwest's Fiscal Year 2022 increased from the prior year as a direct result of an increased average monthly capacity factor (29.2% for Energy Northwest Fiscal Year 2022 versus 29.1% for Energy Northwest Fiscal Year 2021), and a higher average wind speed of 2.9% (15.88 miles per hour) for Energy Northwest Fiscal Year 2022 versus Energy Northwest Fiscal Year 2021 (15.43 miles per hour). Generation for both Energy Northwest Fiscal Year 2021 and 2022 were above the five year average gross generation for the Nine Canyon Wind Project.

In September 2022, Energy Northwest established a decommissioning account at U.S. Bank, for the purpose of investing funds received from Phase I and Phase II participants, and will be used to offset future decommissioning-related expenses, which is currently expected to begin in 2030.

**PROJECT 1**

Project 1 is a partially completed nuclear electric generating project located about 160 miles southeast of Seattle, Washington, on DOE's Hanford Reservation, approximately one and one-half miles east of Columbia. Project 1 was terminated in May 1994. The Project 1 Project Agreement and the Project 1 Net Billing Agreements ended upon termination of Project 1, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement. The Project 1 Post Termination Agreement facilitates the administration, budgeting and payment processes post termination. After termination, Energy Northwest offered to sell assets in the form of uninstalled operating equipment and construction materials since there was no market for the sale of Project 1 in its entirety. Certain of these assets have been sold.

Energy Northwest has planned for the demolition and restoration of Project 1 and is now maintaining the site to support re-use activities. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with site maintenance activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements. The Project 1 Post Termination Agreement requires Bonneville to fund this site remediation plan for Project 1, which is expected to be complete in June 2024. The remaining estimate for site remediation activities as of February 7, 2023, is estimated at $5.0 million in 2023 dollars. Bonneville has placed funds (approximately $18 million as of June 30, 2022), in an external interest-bearing account in order to have sufficient funds for the eventual final remediation, with any funds remaining after final remediation efforts being returned to Bonneville.

**PROJECT 3**

Project 3 is a partially completed nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington, which was terminated in June 1994. The Project 3 Project Agreement and the Project 3 Net Billing Agreements ended upon termination of Project 3, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement. The Project 3 Post Termination Agreement facilitates the administration, budgeting and payment processes post termination.

After termination, Energy Northwest offered to sell assets in the form of uninstalled operating equipment and construction materials since there was no market for the sale of Project 3 in its entirety. In 1995, a group from Grays Harbor County, Washington, interested in local economic development, formed the Satsop Redevelopment Project. The Satsop Redevelopment Project is a coalition of governments established by inter-local agreement between Grays Harbor County, the Port of Grays Harbor and Public Utility District No. 1 of Grays Harbor County. In 1999, Energy Northwest transferred the Project 3 site properties and facilities (other than the Satsop combustion turbine site) to such local public agencies for purposes of economic development. In connection with that transfer, these local public agencies assumed responsibility for any required site remediation. The Satsop combustion turbine site was sold in 2001 to Duke Energy Grays Harbor LLC for $10,000,000.

**PROJECTS 4 AND 5**

Projects 4 and 5 were terminated in January 1982. The Project 4/5 Bonds went into default on July 22, 1983. After extended litigation and ultimate settlement, all trusts created under the resolution authorizing the Project 4/5 Bonds were terminated, and Energy Northwest and the trustee under the resolution were released from all of their obligations thereunder.

**ENERGY SERVICES AND DEVELOPMENT**

More than two decades ago, Energy Northwest set out to develop new sources of electricity generation and provide energy and environmental related services to meet the needs of its member utilities and the region. Since 1992, Energy Northwest has provided a wide range of calibration services and chemical/environmental analysis services to utility, municipal, commercial, and nuclear customers along with operations and maintenance services for various hydroelectric locations. Energy Northwest is a founding member of NoaNet, offering access to a fiber-optic cable network licensed from Bonneville and other broadband providers. Energy Northwest supports the local economy and DOE by offering facilities for lease to early stage businesses, the Pacific Northwest National Laboratory and Hanford contractors.

Energy Northwest continues to support the electric industry with calibration laboratory services with a solid base of existing customers. The Environmental Laboratory continues to expand its base of customers and provides additional services to the Columbia Generating Station during its refueling outage. In August 2021, Energy Northwest was awarded a contract from Bechtel National Inc. ("BNI") to establish service agreements or extend current warranties with the original equipment manufacturer for the BNI instrumentation at the Hanford Tank Waste Treatment and Immobilization Plant. The contract period for performance was recently extended through December 2023.

Energy Northwest was the recipient of a Washington State Department of Commerce ("Commerce") grant in 2015, which was finalized in 2017. The Commerce grant was an award of up to $3.0 million under the Washington Clean Energy Funds' Grid Modernization Grant Program. The grant was to develop the Horn Rapids Solar Storage and Training ("HRSST") project. The HRSST project included the development of a four MWdc photovoltaic solar project coupled with a one MW/four MWh basic lithium-ion battery storage. Energy Northwest collaborated and came to agreement with the City of Richland for the Battery Energy Storage System ("BESS") storage portion of the HRSST. The Energy Northwest Board of Directors approved the project; and the City of Richland signed a participant agreement in October 2018. Construction of the BESS was initiated in Energy Northwest's Fiscal Year 2020 and both the solar project (that is not owned by Energy Northwest) and BESS, were completed in Energy Northwest's Fiscal Year 2021 and the project is now operational.

Energy Northwest continues to expand its presence in electric vehicle infrastructure development. In January 2018, Energy Northwest finalized agreements to be the lead agency in the Washington State Department of Transportation Electric Vehicle Infrastructure Transportation Alliance Project. Energy Northwest and partners installed direct current fast-charging stations in central Washington to alleviate the "charging gap" or long distances between charging stations that made cross-state electric vehicle travel difficult. In 2021, Energy Northwest received grants from the Commerce Clean Energy Fund and TransAlta Coal Transition fund to install a network of electric vehicle charging stations along the US 12 corridor. Energy Northwest also received funding from Pacific Power for installation of two electric vehicle charging sites in Dayton, Washington and Naches, Washington. In addition, Energy Northwest received a small grant relating to the operation and maintenance of charging stations installed in prior years. See "—THE COLUMBIA GENERATING STATION—Recent Developments."

In October 2020, the DOE announced it had selected X-energy and TerraPower-GE Hitachi for its Advanced Reactor Demonstration Program, which provides initial funding for two domestic advanced nuclear reactor projects. Energy Northwest was listed as a utility partner on both applications. This program is not included in the Net Billed Projects, and would be a separate system or part of a separate system of Energy Northwest.

In January 2021, Energy Northwest entered a joint development agreement with X-energy to provide advice and project support for an advanced nuclear reactor development project that is being funded in part by the DOE. On April 1, 2021, Energy Northwest, X-energy LLC and Public Utility District No. 2 of Grant County established the TRi Energy Partnership to collaborate and share resources to evaluate, develop and build a commercial Xe-100 advanced nuclear reactor. Through the DOE Loan Program Office, Energy Northwest and X-energy plan to build a commercial Xe-100 advanced nuclear reactor on the previously licensed site north of Richland, Washington.

Energy Northwest is currently in contract negotiations with TerraPower-GE Hitachi to finalize scope and timing for an advanced nuclear reactor development project slated for completion in Wyoming. The project will be funded in part by the DOE. Similar to the X-energy project described above, as part of the DOE Advanced Reactor Demonstration Program, this project is also expected to be one of the nation's first commercial advanced nuclear reactors.

In 2021, Energy Northwest entered into a lease option agreement with Tucci Energy Services, for the purpose of developing a solar project on undeveloped land located approximately three miles north of Richland. The lease option agreement included the option of leasing up to 300 acres of the unused land for future development. This land is part of 300 acres Energy Northwest purchased from Tri-City Development Council in 2016 for future development.

Energy Northwest has a robust Operations and Maintenance sector that supports public power in the areas of operations and maintenance of generating facilities and electric utility operations. Portland Hydro is a five-year agreement for operating and maintaining two powerhouses on the Bull Run River for the City of Portland, the agreement runs through Fiscal Year 2023. Pursuant to a year-to-year agreement, Energy Northwest operates and maintains the 25 MW Tieton project located at Rimrock Lake in Yakima County, Washington owned by the City of Burbank, California. Energy Northwest entered into an agreement with Eugene Water and Electric Board ("EWEB") to operate and maintain the Stone Creek Hydro project located on the Oak Grove Fork of the Clackamas River. The agreement is for a five-year period to maintain the 12 MWe project for EWEB and was signed in May of 2020.

## RISK MANAGEMENT

### Insurance

Energy Northwest maintains a risk management and insurance program, which incorporates a combination of self-insurance, commercial insurance and nuclear property and liability insurance. Claims relating to Project 1, Columbia or Project 3 that are not covered by insurance are paid from revenues under the related Project Net Billing Agreements.

Nuclear insurance includes liability coverage, property damage, decontamination and premature decommissioning coverage and accidental outage and/or extra expense coverage. The liability coverage is governed by the Price-Anderson Act, while the property damage, decontamination and premature decommissioning coverage are defined by the Code of Federal Regulations. Energy Northwest continues to maintain all regulatory required limits as defined by the NRC, Code of Federal Regulations and the Price-Anderson Act. The NRC requires Energy Northwest to certify nuclear insurance limits on an annual basis. Energy Northwest intends to maintain insurance against nuclear risks to the extent such insurance is available on reasonable terms and in an amount and form consistent with customary practice. Energy Northwest is self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered under policy exclusions, terms or limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Such losses could have an effect on Energy Northwest's results of operations and cash flows.

The Price-Anderson Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Price-Anderson Act sets the statutory limit of public liability for a single nuclear incident at $13.660 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection ("SFP"). Energy Northwest has $450,000,000 of liability insurance as the first layer of protection. If any U.S. nuclear generation plant has a significant event that exceeds the liability insurance, every operating licensed reactor in the U.S. is subject to an assessment up to $137,608,800 plus state insurance premium tax. Assessments are limited to $20,496,000 per reactor, per year, per incident, excluding taxes. The SFP combines the contribution from 96 operating reactors to create the secondary layer of protection at $13.210 billion. The SFP is adjusted at least every five years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1,060,000,000 nuclear decontamination and property damage insurance and required the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Energy Northwest has aggregate coverage in the amount of $2,750,000,000, which is subject to a $5,000,000 deductible per accident.

If there is accidental property loss and/or a nuclear release originating from a cyber event, both the nuclear property and liability policies extend coverage as defined above under Code of Federal Regulations and the Price-Anderson Act. Accidental property loss with on-site decontamination has protection up to $3.24 billion, and nuclear liability coverage up to $13.660 billion. Insurance coverage is reviewed annually based on current Energy Northwest needs and known cyber risks and control assessment.

**Natural Disaster and Climate Change**

Washington State has experienced various natural disasters, including wildfires, mudslides, floods, droughts, windstorms, volcanic eruption (Mount St. Helens in 1980), and earthquakes (in Western Washington). The last earthquake in Eastern Washington was in 1936 and had a magnitude estimated between 6.1 and 6.4.

Climate change may intensify and increase the frequency of extreme weather events, such as drought, wildfires, floods and heat waves. Under Washington law, any person, firm or corporation may be liable if it creates or allows extreme fire hazards to exist and which hazards contribute to the spread of the fires.

**Physical Security**

Physical security at Columbia is regulated by the NRC 10 CFR 73.55 (Requirements for physical protection of licensed activities in nuclear power reactors against radiological sabotage). This regulation requires each licensee, including Columbia, to have a NRC approved Physical Security Plan, a Training and Qualification Plan, a Safeguards Contingency Plan and a Cyber Security Plan. The requirements that Columbia implements as part of its operating license ensures protection against radiological sabotage and theft of special nuclear material.

**Cyber Security**

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.

Cyber security at Columbia is regulated by the NRC under 10 CFR 73.54 (Protection of Digital Computer and Communication Systems and Networks). This regulation requires the creation of a comprehensive cyber security program that includes analysis and classification of all digital assets, a structured cyber security defensive architecture, application of rigorous technical controls, and an active process to monitor internal and external risks to ensure protection of digital plant equipment. Columbia fully implemented the requirements of 10 CFR 73.54 as of December 31, 2017.

Overall, Columbia's cyber security program provides protections through four primary methods. The first is physical protection; as a nuclear facility, there is extensive physical security including restricted public access, numerous physical barriers, continuous surveillance, and armed officers with authorization to use deadly force to protect the facility. The second is isolation of plant networks with no access to the internet, which eliminates the risk of attacks from the internet being able to control, modify, or disrupt critical plant networks. The third is implementation of cyber security technical controls inside these isolated and protected networks to provide a robust defense-in-depth. Every individual digital asset is analyzed against a catalog of technical controls which are used to ensure that potential vulnerabilities and attack pathways are adequately mitigated. The fourth is implementation of comprehensive programmatic elements that include administrative controls on personnel, active monitoring, continuous reviews of vendor vulnerabilities and periodic security control updates.

Columbia's last full cyber security program inspection by the NRC was in the Fall of 2022. The NRC concluded that Columbia had adequately implemented the requirements but identified two very low security significance violations. Columbia is on a two-year inspection cycle on an on-going basis with the next full inspection in the fall of 2024.

In regards to recent cyber security data breaches impacting federal agencies, Energy Northwest has not found any evidence or received notifications that would indicate any direct impact. However, based on conservative recommendations, Energy Northwest has implemented security patches and disabled certain software to further protect from the risk of cyber attacks.

See "Insurance" for information on Energy Northwest's insurance coverage against costs relating to certain cyber events.

**Russian Energy and Sanctions**

As previously described under "—THE COLUMBIA GENERATING STATION—Nuclear Fuel," Energy Northwest has existing U.S. based inventory and supply contracts to fulfill the Columbia reload requirements through the 2029 refueling. In addition, there are inventories in storage, as well as a longer-term supply contract with western European suppliers to meet the reload requirements through the 2035 refueling. Energy Northwest is well insulated against future uranium market price increases and/or supply disruptions that could arise from prolonged U.S. sanctions on imports of uranium from Russia into the U.S. Energy Northwest's supply contracts are subject to escalation based on inflation indices. As markets have developed, the spot purchase and long-term purchases have saved Energy Northwest millions of dollars, specifically over $87 million for the spot purchase.

Sanctions against Russia are not expected to adversely impact Energy Northwest, given that all of Energy Northwest's long-term fuel storage and supply contracts are with non-Russian suppliers.

## NET BILLED PROJECTS LITIGATION AND CLAIMS

Energy Northwest is a party to various claims and legal actions arising in the normal course of business. The following is a discussion of certain litigation and claims to which Energy Northwest is a party relating to the Net Billed Projects:

Energy Northwest v. United States of America (DOE or "government"). On August 14, 2020, Energy Northwest and the United States entered into an Addendum to Settlement Agreement ("Settlement Agreement") under Energy Northwest v. United States, No. 11-447C (Fed. Cl. filed July 7, 2011). The Settlement Agreement provided that Energy Northwest will be reimbursed by the government for its allowable expenses, as defined in the Settlement Agreement, related to DOE's continued failure to accept used nuclear fuel under the Standard Contract signed between Energy Northwest and DOE in 1983.

Under the Settlement Agreement, Energy Northwest is required to submit a claim for reimbursement to DOE annually for each year of Energy Northwest Fiscal Years through December 31, 2025. The claim submission deadline is January 31 of the calendar year following Energy Northwest's fiscal year end. On June 25, 2021, Energy Northwest received $8,488,241.98 for Energy Northwest's Fiscal Year 2020 claim. On January 28, 2022, Energy Northwest submitted its Energy Northwest Fiscal Year 2021 reimbursement claim in the amount $8,698,983. On July 29, 2022, Energy Northwest received $8,294,982.47 for Energy Northwest's Fiscal Year 2021 claim. On January 27, 2023, Energy Northwest submitted its Energy Northwest Fiscal Year 2022 reimbursement claim in the amount $23,643,994.26. The claim was higher than recent years because during the claim period, the ISFSI Expansion Project entered Phase 3 expansion activities that involves construction of four additional storage pads. Additional costs were incurred with nine storage casks that were purchased pursuant to the planned reloading allocations.

The total reimbursement to date from the government to Energy Northwest for partial breach of the Standard Contract is over $146,091,982, of which over $73,794,982, was reimbursed through the claims process for Energy Northwest Fiscal Years 2013 through 2021.

See also "—THE COLUMBIA GENERATING STATION—Nuclear Fuel."

## LEGAL MATTERS

The approving opinion of Foster Garvey P.C., Bond Counsel to Energy Northwest, as to the legality of the Series 2023-A Bonds will be in substantially the form included in Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2023-A BONDS." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the status of the interest on the Series 2023-A Bonds for federal income tax purposes will be in substantially the form included in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2023-A BONDS."

Bond Counsel will also render a supplemental opinion with respect to the validity and enforceability of the Net Billing Agreements and the Assignment Agreements. As to the due authorization, execution and delivery of such Net Billing Agreements and the Assignment Agreements by Bonneville and certain other matters relating to Bonneville, Bond Counsel will rely on the opinion of Bonneville's General Counsel. In rendering its opinion with respect to the Net Billing Agreements, Bond Counsel will assume, among other things, (1) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (2) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreements to which such Participant is a party and that all assignments of any Participants' obligations under the Net Billing Agreements were properly made, and (3) with respect to the Participants' obligations under the Net Billing Agreements, no conflict or violations under applicable law. In rendering its opinion as to the enforceability of the Net Billing Agreements against the Participants, Bond Counsel will assume the continued obligations of Bonneville, and performance by Bonneville of its obligations under, the Net Billing Agreements and Assignment Agreements, and such opinion will not address the effect on the enforceability against the Participants if Bonneville is no longer obligated under the Net Billing Agreements and Assignment Agreements or of nonperformance thereunder by Bonneville. The assumption in the prior sentence will not affect Bond Counsel's opinion as to the enforceability of the Net Billing Agreements and Assignment Agreements against Bonneville. In the event a Participant's obligations under the Net Billing Agreements are no longer enforceable against such Participant, it is the opinion of Bond Counsel that Bonneville is obligated under the Net Billing Agreements, the Assignment Agreements and the 1989 Letter Agreement to pay to Energy Northwest the amounts required to be paid by such Participant under the Net Billing Agreements. A copy of the proposed form of supplemental opinion of Bond Counsel is included in Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2023-A BONDS."

See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Assignment Agreements" for a discussion of Bonneville's agreement to pay directly to Energy Northwest certain amounts that are not paid by a Participant and for a discussion of certain of Bonneville's obligations under the Assignment Agreements.

Certain legal matters, including the enforceability against Bonneville of the Net Billing Agreements and the Assignment Agreements, will be passed upon 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, Counsel to the Underwriters.

## TAX MATTERS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2023-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). Special Tax Counsel is of the further opinion that interest on the Series 2023-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Special Tax Counsel observes that, for tax years beginning after December 31, 2022, interest on the Series 2023-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual, or receipt of interest on, the Series 2023-A Bonds In rendering its opinion, Special Tax Counsel has relied on the opinion of Bond Counsel as to the validity of the Series 2023-A Bonds and the due authorization and issuance of the Series 2023-A Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2023-A BONDS."

To the extent the issue price of any maturity of the Series 2023-A Bonds is less than the amount to be paid at maturity of such Series 2023-A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2023-A Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the Series 2023-A Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Series 2023-A Bonds is the first price at which a substantial amount of such maturity of the Series 2023-A Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the Series 2023-A Bonds accrues daily over the term to maturity of such Series 2023-A Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such Series 2023-A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2023-A Bonds. Beneficial Owners of the Series 2023-A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2023-A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2023-A Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2023-A Bonds is sold to the public.

Series 2023-A Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

Title XIII of the 1986 Act, the 1986 Code and the 1954 Code impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series 2023-A Bonds. Energy Northwest and Bonneville have made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the Series 2023-A Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2023-A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2023-A Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring), or any other matters coming to the attention of Special Tax Counsel after the date of issuance of the Series 2023-A Bonds may adversely affect the value of, or the tax status of interest on, the Series 2023-A Bonds. Accordingly, the opinion of Special Tax Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Special Tax Counsel is of the opinion that interest on the Series 2023-A Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of amounts treated as interest on, the Series 2023-A Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel expresses no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the 1986 Act, the 1986 Code or the 1954 Code or court decisions may cause interest on the Series 2023-A Bonds to be subject, directly or indirectly, in whole or in part, to federal income taxation or to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such legislative proposals or clarification of the 1986 Act, the 1986 Code or the 1954 Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the Series 2023-A Bonds. Prospective purchasers of the Series 2023-A Bonds should consult their own tax advisors regarding the potential impact of any pending or proposed federal or state tax legislation, regulations or litigation, as to which Special Tax Counsel expresses no opinion.

The opinion of Special Tax Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2023-A Bonds for federal income tax purposes. The opinion is not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of Energy Northwest or Bonneville, or about the effect of future changes in the 1986 Act, the 1986 Code, the 1954 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville has covenanted, however, to comply with applicable requirements of the 1986 Act, the 1986 Code and the 1954 Code.

Unless separately engaged, Special Tax Counsel is not obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2023-A Bonds in the event of an audit examination by the IRS. Under current procedures, Beneficial Owners would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which Energy Northwest or Bonneville legitimately disagrees may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2023-A Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2023-A Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

Payments on the Series 2023-A Bonds generally will be subject to U.S. information reporting and possibly to "backup withholding." Under Section 3406 of the Code and applicable U.S. Treasury Regulations issued thereunder, a non-corporate Beneficial Owner of the Series 2023-A Bonds may be subject to backup withholding with respect to "reportable payments," which include interest paid on the Series 2023-A Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the Series 2023-A Bonds. The payor will be required to deduct and withhold the prescribed amounts if (i) the payee fails to furnish a U.S. taxpayer identification number ("TIN") to the payor in the manner required, (ii) the IRS notifies the payor that the TIN furnished by the payee is incorrect, (iii) there has been a "notified payee underreporting" described in Section 3406(c) of the Code or (iv) the payee fails to certify under penalty of perjury that the payee is not subject to withholding under Section 3406(a)(1)(C) of the Code. Amounts withheld under the backup withholding rules may be refunded or credited against a Beneficial Owner's federal income tax liability, if any, provided that the required information is timely furnished to the IRS. Certain Beneficial Owners (including among others, corporations and certain tax-exempt organizations) are not subject to backup withholding. The failure to comply with the backup withholding rules may result in the imposition of penalties by the IRS.

## RATINGS

Moody's Investors Service ("Moody's"), S&P Global Ratings ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2023-A Bonds the ratings of "Aa2" (positive outlook), "AA-" (stable outlook) and "AA" (stable outlook), respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the Series 2023-A 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 or marketability of the Series 2023-A Bonds.

## UNDERWRITING

J.P. Morgan Securities LLC ("JPMS"), Wells Fargo Bank, National Association ("WFBNA"), BofA Securities, Inc., and Citigroup Global Markets Inc. (collectively, the "Underwriters") have jointly and severally agreed, subject to certain conditions, to purchase the Series 2023-A Bonds from Energy Northwest and to make a bona fide public offering of such Series 2023-A Bonds at not in excess of the public offering prices (or prices corresponding to such yields) set forth on the inside cover page of this Official Statement. The aggregate Underwriters' compensation under the contract of purchase for the Series 2023-A Bonds is $2,125,943.99. The Underwriters' obligations under the contract of purchase are subject to certain conditions precedent contained in the contract of purchase. The Underwriters will be obligated to purchase all of the Series 2023-A Bonds being sold under the contract of purchase if any of the Series 2023-A Bonds are purchased.

The Series 2023-A Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such Series 2023-A Bonds into investment trusts) at prices lower than such initial offering prices and such initial offering prices may be changed from time to time by the Underwriters.

JPMS has entered into negotiated dealer agreements (each, a "Dealer Agreement") with each of Charles Schwab & Co., Inc. ("CS&Co.") and LPL Financial LLC ("LPL") for the retail distribution of certain securities offerings at the original issue prices. Pursuant to each Dealer Agreement, each of CS&Co. and LPL may purchase Series 2023-A Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any Series 2023-A Bonds that such firm sells.

Wells Fargo Corporate & Investment Banking (which may be referred to elsewhere as "CIB," "Wells Fargo Securities" or "WFS") is the trade name used for the corporate banking, capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including WFBNA, a member of the National Futures Association, which conducts its municipal securities sales, trading and underwriting operations through the Wells Fargo Bank, N.A. Municipal Finance Group, a separately identifiable department of WFBNA, registered with the U.S. Securities and Exchange Commission as a municipal securities dealer pursuant to Section 15B(a) of the Securities Exchange Act of 1934.

WFBNA, acting through its Municipal Finance Group, has entered into an agreement (the "WFA Distribution Agreement") with its affiliate, Wells Fargo Clearing Services, LLC (which uses the trade name "Wells Fargo Advisors") ("WFA"), for the distribution of certain municipal securities offerings, including the Series 2023-A Bonds. Pursuant to the WFA Distribution Agreement, WFBNA will share a portion of its underwriting or remarketing agent compensation, as applicable, with respect to the Series 2023-A Bonds with WFA. WFBNA has also entered into an agreement (the "WFSLLC Distribution Agreement") with its affiliate Wells Fargo Securities, LLC ("WFSLLC"), for the distribution of municipal securities offerings, including the Series 2023-A Bonds. Pursuant to the WFSLLC Distribution Agreement, WFBNA pays a portion of WFSLLC's expenses based on its municipal securities transactions. WFBNA, WFSLLC, and WFA are each wholly-owned subsidiaries of Wells Fargo & Company.

BofA Securities, Inc. has entered into a distribution agreement with its affiliate Merrill Lynch, Pierce, Fenner & Smith Incorporated ("MLPF&S"). As part of this arrangement, BofA Securities, Inc. may distribute securities to MLPF&S, which may in turn distribute such securities to investors through the financial advisor network of MLPF&S. As part of this arrangement, BofA Securities, Inc. may compensate MLPF&S as a dealer for their selling efforts with respect to the Series 2023-A Bonds.

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

The Underwriters have provided the following information to Energy Northwest for inclusion in this Official Statement. The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Certain of the Underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various investment banking services for Energy Northwest and 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 respective 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 of Energy Northwest and Bonneville.

WFBNA has extended credit in other transactions to Energy Northwest and in other transactions supported by obligations of Bonneville under lease-purchase agreements.

BofA Securities, Inc. is an affiliate of Bank of America, N.A. which has extended credit in other transactions to Energy Northwest.

Citigroup Energy, Inc., an affiliate of Citigroup, Inc., has entered into a power sales contract with Bonneville.

## CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934, as amended ("Rule 15c2-12"), Energy Northwest and Bonneville will enter into Continuing Disclosure Agreements, to be dated the date of delivery of the Series 2023-A Bonds, for the benefit of the owners and beneficial owners of the Series 2023-A Bonds, to provide certain financial information and operating data relating to Energy Northwest (the "Energy Northwest Annual Information"), certain financial information and operating data relating to Bonneville (the "Bonneville Annual Information" and, together with Energy Northwest Annual Information, the "Annual Information") and to provide timely notices of the occurrence of certain enumerated events with respect to the Series 2023-A Bonds. Energy Northwest Annual Information is to be provided not later than 180 days after the end of Energy Northwest Fiscal Year, commencing with the Energy Northwest Fiscal Year ending June 30, 2023. The Bonneville Annual Information is to be provided not later than 180 days after the end of the Federal Columbia River Power System fiscal year, commencing with the Bonneville Fiscal Year ending September 30, 2023. The Annual Information and notices of aforesaid enumerated events will be filed with the Municipal Securities Rulemaking Board (the "MSRB"). Currently, the information filed with the MSRB is available to the public without charge through its Electronic Municipal Market Access system ("EMMA"). The nature of the information to be provided and notices of such enumerated events is set forth in Appendix J—"SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS."

Energy Northwest has previously entered into continuing disclosure undertakings under Rule 15c2-12. With respect to previous undertakings for the Net Billed Bonds, Energy Northwest has filed its annual financial information and operating data in a timely manner. For the Nine Canyon Wind Project bonds, although the "Other Purchasers" information was not updated by Energy Northwest each year, each "Other Purchaser" has filed its annual financial statements on EMMA. Fitch Ratings upgraded its rating on the Nine Canyon Wind Project bonds on November 25, 2019, and although Energy Northwest put a notice on its website in a timely manner, it filed notice of such rating change on EMMA on January 8, 2020. On April 21, 2021, Energy Northwest filed a notice on EMMA that it extended the maturity of its Columbia Generating Station Electric Revenue Bond Anticipation Note, 2020C (Tax-Exempt) and 2020D (Taxable) by two months in November 2020, as permitted by the resolution authorizing the notes and the Loan Agreement dated May 1, 2020, between Wells Fargo Bank, National Association and Energy Northwest.

## INITIATIVE AND REFERENDUM

Under the State Constitution, the voters of the State have the ability to initiate legislation and modify existing legislation through the powers of initiative and referendum, respectively. The initiative power in Washington may not be used to amend the State Constitution. Initiatives and referenda are submitted to the voters upon receipt of a petition signed by at least 8% (initiative) and 4% (referenda) of the number of voters registered and voting for the office of Governor at the preceding regular gubernatorial election. Any law approved in this manner by a majority of the voters may not be amended or repealed by the State Legislature within a period of two years following enactment, except by a vote of two-thirds of all the members elected to each house of the State Legislature. After two years, the law is subject to amendment or repeal by the State Legislature in the same manner as other laws. Any such initiatives or referenda could affect the laws governing Energy Northwest. There have been several state initiatives involving energy issues, including one requiring certain electric utilities to obtain a percentage of their electricity from renewable resources.

## BANKRUPTCY

A municipality such as Energy Northwest must be specifically authorized under state law to seek relief under Chapter 9 of the United States Bankruptcy Code (the "Bankruptcy Code"). Chapter 39.64 RCW, entitled the "Taxing District Relief Act," permits any "taxing district" (defined to include any municipality or political subdivision, such as Energy Northwest) to voluntarily petition for relief under the predecessor statute to the Bankruptcy Code. A creditor cannot bring an involuntary bankruptcy proceeding against a municipality, including Energy Northwest. Under Chapter 9, a federal bankruptcy court may not appoint a receiver for a municipality or order the dissolution or liquidation of the municipality. The federal bankruptcy courts have some discretionary powers under the Bankruptcy Code. Municipalities in the State, including Energy Northwest, are expressly authorized to carry out a plan of readjustment if approved by the appropriate court. Should Energy Northwest file for bankruptcy, there could be adverse effects on the holders of the Electric Revenue Bonds, including the Series 2023-A Bonds.

Under the Bankruptcy Code, if Energy Northwest became a debtor in a federal bankruptcy proceeding, the owners of the Electric Revenue Bonds would continue to have a statutory lien on revenues as described in "SECURITY FOR THE NET BILLED BONDS" after the commencement of the bankruptcy case so long as the revenues constitute "special revenues" within the meaning of the Bankruptcy Code. "Special revenues" are defined under the Bankruptcy Code to include, among other things, receipts by local governments from the ownership, operation or disposition of projects or systems that are primarily used to provide utility services. The Bankruptcy Code provides that "special revenues" can be applied to necessary operating expenses of the project or system before they are applied to other obligations. It is not clear which expenses would constitute necessary operating expenses.

If Energy Northwest is in bankruptcy, parties (including the Trustee and the holders of the Series 2023-A Bonds) may be prohibited from taking any action to collect any amount from Energy Northwest or to enforce any obligation of Energy Northwest, unless the permission of the bankruptcy court is obtained.

## MISCELLANEOUS

The references, excerpts and summaries contained herein of the Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements, the Post Termination Agreements and any other documents or agreements referred to herein do not purport to be complete statements of the provisions of such documents or agreements, and reference should be made to such documents or agreements for a full and complete statement of all matters relating to the Series 2023-A Bonds, the agreements securing the Series 2023-A Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements and the Post Termination Agreements and other reports, documents, agreements and studies referred to herein and in the Appendices hereto are available upon request at the office of Energy Northwest in Richland, Washington.

The authorizations, agreements and covenants of Energy Northwest are set forth in the Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the Series 2023-A Bonds is to be construed as a contract with the holders of such Series 2023-A Bonds. Any statements made in this Official Statement involving matters of opinion or estimates, whether or not expressly so identified, are intended merely as such and not as representations of fact.

Bonneville has furnished the information herein relating to it.

# APPENDIX A

## BONNEVILLE POWER ADMINISTRATION

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## APPENDIX A

## BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest ("Energy Northwest" or the "Issuer") by Bonneville for use in the Official Statement, dated May 2, 2023, of the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2023-A, Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A, and Project 3 Electric Revenue Refunding Bonds, Series 2023-A (collectively, the "Series 2023-A Bonds"). (Energy Northwest's Project 1, Project 3, and Columbia Generating Station are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as the "Net Billed Projects." Bonds issued for the Net Billed Projects, including but not limited to the Series 2023-A Bonds, are referred to collectively in this Appendix A as "Net Billed Bonds.") 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 2023-A 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 2024 of approximately 9,741 annual average megawatts (defined below) under median water conditions and approximately 8,039 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 2024, it will meet 7,803 annual average megawatts of loads, of which approximately 86 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 $951 million in full and on time for Bonneville's fiscal year ended September 30, 2022 ("Fiscal Year 2022"). 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 cash deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the Direct Pay Agreements, and other operating and maintenance expenses, including lease rental payments for transmission facilities and the costs of electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. For descriptions of the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements, see the Official Statement under the heading "SECURITY FOR THE NET-BILLED BONDS–Net Billing and Related Agreements." 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 cash deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the Direct Pay Agreements, 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 "SECURITY FOR THE NET BILLED 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 2022-2023." 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. Bonneville is engaged in discussions on key issues and continues to hold public workshops in Fiscal Year 2023 to discuss proposals. In July 2023, Bonneville expects to release a draft policy that will reflect 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 expects to release a final policy and record of decision in January 2024. In Fiscal Year 2024 and Fiscal Year 2025, Bonneville expects to conduct a process to develop the rate methodology that will be applicable to the new long-term power sales contracts. In Fiscal Year 2026, Bonneville expects to execute new long-term power sales contracts and other agreements.

## CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

### Fiscal Year 2022 Financial Results

In Fiscal Year 2022, Bonneville made its scheduled United States Treasury payments on time and in full for the 39th consecutive year. Bonneville recorded net revenues in Fiscal Year 2022 of $964 million, an increase of approximately $566 million more than the prior fiscal year net revenues of $398 million. The significant increase in Fiscal Year 2022 year-end agency net revenues is primarily due to a $754 million increase in Power Services gross sales due to above-average hydro power supply sales and higher short-term energy market prices that Bonneville obtained for the sale of seasonal surplus energy (that were more than double the average sales price forecast when establishing current rates). For additional details related to Fiscal Year 2022 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2022." Bonneville finished Fiscal Year 2022 with Total Financial Reserves (as hereinafter defined) of approximately $1.8 billion (Power Services' Total Financial Reserves of $1.4 billion and Transmission Services' Total Financial Reserves of $445 million), which is an increase of approximately $779 million, or 74 percent more 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 2022 with RAR of approximately $1.5 billion (Power Services' RAR of approximately $1.2 billion and Transmission Services' RAR of approximately $267 million), an increase of approximately 83 percent from the prior year. The increase in Fiscal Year 2022 year-end agency RAR is primarily due to a $754 million increase in Power Services gross sales, as discussed above. As a result of the record-breaking net revenues in Fiscal Year 2022, Bonneville finished the year with a substantial RAR balance which is equivalent to the amount of cash needed to meet operating expenses for 233 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 360. 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 2022 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2022." Based on the Fiscal Year 2022 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 "—Current Bonneville Power and Transmission Rates."

**Fiscal Year 2023 Expectations**

The forward-looking financial information included in this Fiscal Year 2023 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 2023 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 2023 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 2023 Expectations section and should not be read to do so.

As of February 14, 2023, Bonneville forecast that it would finish Fiscal Year 2023 with RAR of $1 billion (Power Services' RAR of $733 million and Transmission Services' RAR of $286 million), or approximately $500 million less than the $1.5 billion RAR as measured as of the end of Fiscal Year 2022. The forecast decrease in Fiscal Year 2023 RAR is primarily attributable to the Power and Transmission Reserves Distribution Clauses that triggered for application to Fiscal Year 2023 rates, which includes 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 an additional $200 million that has been set aside for other designated purposes (see "—Current Bonneville Power and Transmission Rates"). 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.

Through the first quarter of Fiscal Year 2023, total operating expenses were $330 million higher when compared to the first quarter of Fiscal Year 2022. See "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Unaudited Results for the Three Months ended December 31, 2022" and Appendix B-2—"FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE THREE MONTHS ENDED DECEMBER 31, 2022." The primary driver is due to purchased power expense, which is $291 million higher than the same period in the prior year due to the combination of low water availability for power generation and high market prices. Through the remainder of Fiscal Year 2023, Bonneville expects to incur additional increased purchased power expense due to continued poor water conditions, which could result in a further decline in Fiscal Year 2023 year-end net revenues and RAR levels. 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 2023 United States Treasury payment responsibility on time and in full.

**Current Bonneville Power and Transmission Rates**

To establish rates of general applicability for electric power and for transmission and related services, in July 2021, Bonneville filed final proposed power and transmission rates for Fiscal Year 2022 and Fiscal Year 2023 (the "2022-2023 Rate Period") with FERC for its review. FERC granted final confirmation and approval of such rates in March 2022. The rates approved by FERC are referred to herein as the "Final 2022-2023 Rates". The Final 2022-2023 Rates are the subject of litigation. See "BONNEVILLE LITIGATION—Fiscal Year 2022-2023 Rates Challenge."

The Final 2022-2023 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 "2020-2021 Rate Period"). Average Tier 1 PF Rates decreased by 2.5 percent, to $34.93 per megawatt hour, and the average Tier 2 PF Rates increased by six percent, to $33.65 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." Weighted average transmission rates increased by 5.4 percent, 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 2022-2023 Rates did not trigger for application to Fiscal Year 2022 or Fiscal Year 2023 power or transmission rate levels; however, a rate mechanism referred to as the "Reserves Distribution Clause" or "RDC" has triggered for application to Power Services and Transmission Services Fiscal Year 2023 rates. An RDC is based on RAR level thresholds by business line at September 30 and, if RAR levels exceed 120 Days Cash On Hand, could result in a decision to decrease certain Power Services or Transmission Services rates in either year of the rate period or amounts could be retained by Bonneville for other certain purposes. The portions of the Power RDC and Transmission RDC that result in rate reductions being implemented in Fiscal Year 2023, as described below, will have the effect of reducing Bonneville's net revenues in Fiscal Year 2023.

On September 30, 2022, Power Services' RAR were $1.2 billion and the total RAR were $1.5 billion, resulting in a Power RDC triggering in the amount of $500 million (which is the maximum amount available for a Power RDC under the Final 2022-2023 Rates) for application to certain Power Services rate levels in Fiscal Year 2023. 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. 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 are being applied to power customer bills through September 2023. In addition to the rate reduction being applied in Fiscal Year 2023, $100 million of the Power RDC amount is being held in Total Financial Reserves for debt reduction in Fiscal Year 2023 (either for early payment of debt or revenue financing of capital expenditures, with any unused amount at the end of Fiscal Year 2023 becoming available to support Bonneville's liquidity or increase the probability of a Power RDC triggering at the end of Fiscal Year 2023), and $50 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 Power RDC is being challenged in court. See "BONNEVILLE LITIGATION— Fiscal Year 2023 Power RDC Challenge."

On September 30, 2022, Transmission Services' RAR were $267 million and the total RAR were $1.5 billion, resulting in a Transmission RDC triggering in the amount of $63 million. The Administrator determined that $13 million of this amount would be applied to reduce Transmission Services rates in Fiscal Year 2023 (from December 2022 through September 2023) and the remaining $50 million would be retained in Total Financial Reserves to offset forecast cost pressures in Fiscal Year 2023, Fiscal Year 2024, and Fiscal Year 2025. In addition to the rate reduction being applied in Fiscal Year 2023, $34 million is being held in Total Financial Reserves to fund forecast Transmission cost increases in Fiscal Year 2023 that will exceed the cost levels assumed when establishing current rates, and $16 million is being held in Total Financial Reserves in support of the proposal to fund forecast Transmission costs in Fiscal Year 2024 and Fiscal Year 2025 ("the "2024-2025 Rate Period") in order to avoid a rate increase for that rate period (over transmission rates currently in effect).

**Proposed Bonneville Power and Transmission Rates for Fiscal Years 2024-2025**

Bonneville began conducting workshops in the spring of 2022 related to developing rates for power and for transmission and related services for the 2024-2025 Rate Period. On December 2, 2022, Bonneville issued its initial rate proposal for the 2024-2025 Rate Period ("the 2024-2025 Initial Rate Proposal"), which began an administrative process that will culminate in a final rate proposal for the 2024-2025 Rate Period (the "2024-2025 Final Rate Proposal") and a record of decision. Bonneville expects to submit the 2024-2025 Final Rate Proposal and record of decision to FERC by the end of July 2023.

Consistent with longstanding policy, the 2024-2025 Initial Rate Proposal was 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." Bonneville's United States Treasury payments are payable after Bonneville's non-federal payment obligations such as payments under the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

*Proposed Power Services Rates*

Based on the 2024-2025 Initial Rate Proposal, in December 2022, Bonneville estimated that average Tier 1 PF Rates would be $34.69 per megawatt hour in the rate period, a decrease of less than one percent from the average Tier 1 PF Rates currently in effect. In its 2024-2025 Initial Power Rate Proposal, Bonneville has proposed $34 million per year of revenue financing in each of the two fiscal years of the rate period for funding a portion of Power Services capital investments. Bonneville also forecast that average Tier 2 PF Rates would be $61.50, an 83 percent increase over the average Tier 2 PF Rates currently in effect. For more details regarding the proposed average Tier 2 PF Rate increase, see "—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."

*Proposed Transmission Services Rates*

Based on the 2024-2025 Initial Rate Proposal, released in December 2022, Bonneville estimated that there would be no change to the Transmission and related rates over the rates currently in effect. In its 2024-2025 Initial Transmission Rate Proposal, Bonneville has proposed $55 million per year of revenue financing in each of the two fiscal years of the rate period for funding a portion of Transmission Services capital investments.

*Proposed Cost Recovery Adjustment Clause and Related Rate Level Adjustment*

In the 2024-2025 Initial Rate Proposal, Bonneville has proposed to continue use of a rate level adjustment mechanism for power and transmission and related rates (referred to herein as the "Cost Recovery Adjustment Clause" or "CRAC"). The CRAC mechanisms proposed in the 2024-2025 Initial Rate Proposal are similar to the CRAC for rates currently in effect. An increase in power or transmission and related rate levels under the proposed CRAC would occur if certain financial information resulted in Power Services' or Transmission Services' expenses that were higher and/or revenues that were lower than anticipated that resulted in Power Services' or Transmission Services' RAR falling below certain thresholds as of September 30.

As proposed in the 2024-2025 Initial Rate Proposal, the CRAC would enable Bonneville to increase certain power and related rate levels over base rates to obtain up to $300 million in additional revenue and would enable Bonneville to increase certain transmission and related rate levels over base rates to obtain up to $100 million of additional revenue in each of the two fiscal years of the rate period, without a time consuming rate proceeding, if Power Services' or Transmission 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' or Transmission 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 or Transmission 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.

The Power Services' or Transmission Services' beginning RAR balance is determined using the financial results of the Federal System for the prior fiscal year that become available each November. Thus, if Power Services' or Transmission Services' RAR were below zero at September 30, 2023, then Bonneville would (subject to a *de minimi*s exception described above) increase power or transmission and related rate levels in December 2023 through September 2024 to obtain additional revenues in Fiscal Year 2024. Likewise, if Power Services' or Transmission Services' RAR were below zero at September 30, 2024, then Bonneville would (subject to a *de minimi*s exception described above) increase power or transmission and related rate levels in December 2024 through September 2025 to obtain additional revenues in Fiscal Year 2025. If a Power or Transmission CRAC were to trigger for application to Fiscal Year 2024 power or transmission and related rate levels, Bonneville would notify customers by November 30, 2023.

In addition to the proposed CRAC mechanisms, under the 2024-2025 Initial Rate Proposal, Bonneville proposed to reserve the ability to institute another full rate proceeding and increase rates or rate levels in the rate period, which Bonneville has estimated would take up to six months.

*Proposed Financial Reserves Policy Surcharge*

As proposed in the 2024-2025 Initial Rate Proposal, Power and Transmission Services rates continue to make available a surcharge rate adjustment mechanism (the "Financial Reserves Policy Surcharge" or "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 or Transmission Services rate levels under the Financial Reserves Policy Surcharge would occur if Power Services' or Transmission Services' RAR fall 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. For Transmission Services, the forecast amount of cash expected to be needed to meet its operating expenses for 60 days is $116 million. As proposed in the 2024-2025 Initial Rate Proposal, 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 in each of the two fiscal years of the rate period if Power Services' RAR were below $319 million at September 30, 2025 or September 30, 2026. In addition, the Financial Reserves Policy Surcharge would allow Bonneville to increase certain transmission and related rate levels over base rates to obtain up to $15 million of additional revenue in each of the two fiscal years of the rate period if Transmission Services' RAR were to fall below $116 million at September 30, 2025 or September 30, 2026. If a Financial Reserves Policy Surcharge were to trigger for application to Fiscal Year 2024 power or transmission rate levels, Bonneville would notify customers by November 30, 2023 and increase power or transmission rate levels to obtain additional revenues in December 2023 through September 2024.

In addition to the proposed CRAC and FRP Surcharge mechanisms that are similar to such mechanisms in the 2022-2023 Rate Period, under the 2024-2025 Initial Rate Proposal, Bonneville proposes to reserve 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.

*Proposed Reserves Distribution Clause*

As proposed in the 2024-2025 Initial Rate Proposal, the Power Services and Transmission Services rates continue the availability of the RDC. The RDC is based on RAR level thresholds by business line at September 30 (subject to a *de minimis* exception described below) and could result in a decision to decrease certain Power Services or Transmission Services rates in either year of the rate period or amounts could be retained by Bonneville for the purposes described below. In order to trigger a distribution under the Reserves Distribution Clause, 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. As proposed in the 2024-2025 Initial Rate Proposal, the first $129 million of an RDC would be deployed to make a downward adjustment to rates. The Administrator has discretion whether to apply the remaining amount of an RDC distribution to make a further downward adjustment to rates or to deploy such amounts to other high-value purposes including, but not limited to, debt retirement or capital investments.

*Uncertainty Regarding Proposed Rates and Rate Levels*

The terms of the 2024-2025 Final Rate Proposal, including but not limited to the terms of base Power Services and Transmission Services rates, and the terms of a Power or Transmission CRAC, Power or Transmission Financial Reserves Policy Surcharge, or Power or Transmission RDC, if any, could differ from those included in the 2024-2025 Initial Rate Proposal. Bonneville's expectations of rate levels for the 2024-2025 Rate Period and the likelihood that a Power or Transmission CRAC, Power or Transmission Financial Reserves Policy Surcharge, or Power or Transmission RDC, if any, would trigger in either year of the two year rate period are subject to change based on numerous factors including Bonneville's financial performance in Fiscal Year 2023 and the terms of the 2024-2025 Final Rate Proposal.

**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. See "—Current Bonneville Power and Transmission Rates."

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 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 Snake River and 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. The parties have agreed on spill for the 2023 fish passage season (approximately April-June 2023) at the Snake River and Columbia River Federal System dams, which are similar to those in effect for the 2022 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."

Bonneville is unable to predict whether and the extent to which the challenges to the 2020 Columbia River System Biological Opinions and Final CRSO EIS will lead to increased costs to Bonneville or to the alteration of Federal System hydro-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 \$3.7 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 77 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 2022.

### 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 2024 (August 1, 2023 through July 31, 2024), the total Federal System would be capable of producing approximately 8,039 annual average megawatts of firm energy under Firm Water conditions and not accounting for transmission line losses. This generation includes approximately 6,636 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,176 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 2024."

Analyses as of April 21, 2023, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2023 water supply for the Columbia River basin will be approximately 79 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 2024 is estimated to be approximately 83 percent of Bonneville's total firm power supply under Firm Water. See the table entitled "Operating Federal System Projects for Operating Year 2024." 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 2024, the Federal System is forecast to generate seasonal surplus energy of 1,297 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 3,221 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 2024" 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 2024" 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 2024. See Footnote 12 in the following table "Operating Federal System Projects for Operating Year 2024."

*Operating Federal System Projects for Operating Year 2024*

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 2024, 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."

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**Operating Federal System Projects for Operating Year 2024(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 | 3,049 | 2,330 | 1924 |
| Hungry Horse | 1952 | 4 | 310 | 146 | 94 | 84 |
| Other Reclamation Projects(6) | | 19 | 300 | 193 | 159 | 135 |
| **1. Total Reclamation Projects** | | 56 | 7,294 | 3,388 | 2,583 | 2,143 |
| **United States Army Corps of Engineers (Corps) Hydro Projects** | | | | | | |
| Chief Joseph | 1955 | 27 | 2,614 | 1,733 | 1,374 | 1,123 |
| John Day | 1968 | 16 | 2,480 | 1,328 | 977 | 762 |
| The Dalles w/o Fishway(7) | 1957 | 22 | 2,080 | 1,030 | 808 | 631 |
| Bonneville | 1938 | 18 | 1,221 | 674 | 535 | 397 |
| McNary | 1953 | 14 | 1,120 | 665 | 556 | 456 |
| Lower Granite | 1975 | 6 | 930 | 279 | 186 | 134 |
| Lower Monumental | 1969 | 6 | 930 | 313 | 212 | 147 |
| Little Goose | 1970 | 6 | 930 | 278 | 188 | 151 |
| Ice Harbor | 1961 | 6 | 693 | 266 | 198 | 151 |
| Libby | 1975 | 5 | 605 | 259 | 247 | 168 |
| Dworshak | 1974 | 3 | 465 | 277 | 203 | 170 |
| Other Corps Projects(8) | | 20 | 574 | 258 | 258 | 203 |
| **2. Total Corps Projects** | | 149 | 14,642 | 7,360 | 5,742 | 4,493 |
| **3. Total Reclamation and Corps Projects (line 1 + line 2)** | | **205** | **21,936** | **10,748** | **8,325** | **6,636** |
| **Non-Federally-Owned Projects** | | | | | | |
| Other Non-Federal Hydro Projects(9) | | 4 | 77 | 31 | 33 | 27 |
| Columbia Generating Station(10) | 1984 | 1 | 1,178 | 1,116 | 1,116 | 1,116 |
| Other Non-Federal Projects(11) | | 7 | - | 33 | 33 | 33 |
| **4. Total Non-Federally-Owned Projects** | | **12** | **1,255** | **1,180** | **1,182** | **1,176** |
| **Federal Contract Purchases** | | | | | | |
| **5. Total Bonneville Contract Purchases(12)** | | **n/a** | **644** | **242** | **234** | **227** |
| **Total Federal System Resources** | | | | | | |
| **6. Total Federal System Resources (line 3 + line 4 + line 5)** | | **217** | **23,835** | **12,170** | **9,741** | **8,039** |

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

(1) Operating Year 2024 is August 1, 2023 through July 31, 2024. 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 not scheduled for refueling in Operating Year 2024 and, therefore, is expected to provide approximately 1,116 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 2024, Bonneville forecasts that it will meet approximately 6,757 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 2024, 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 2024, Bonneville forecasts that it will meet approximately 138 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 2024, Bonneville forecasts that Other Contract Deliveries will be approximately 708 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 2022.

**Bonneville Power Services' Ten Largest Customers By Sales[(1)]**
**(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2022)**

| Customer Name | Approximate % of Sales |
|---|---|
| Snohomish County PUD No 1 (Preference Customer) | 7% |
| Cowlitz County PUD No 1 (Preference Customer) | 4% |
| Portland General Electric Company (Regional IOU) | 4% |
| Transalta Energy Marketing (U.S.) Inc. (Power Marketer) | 4% |
| Pacific Northwest Generating Cooperative[(2)] (Preference Customer) | 4% |
| City of Seattle, City Light Dept. (Preference Customer) | 4% |
| Tacoma Power (Preference Customer) | 4% |
| California Independent System Operator (Power Marketer) | 3% |
| Clark Public Utilities (Preference Customer) | 3% |
| PacifiCorp (Regional IOU) | 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 120 Preference Customers and all of Bonneville's seven federal agency customers purchase Load Following service and for Operating Year 2024 Bonneville forecasts that these loads will be approximately 3,730 annual average megawatts. By contrast, 10 separate Preference Customers purchase on a Slice/Block basis. For Operating Year 2024, Bonneville forecasts that its Slice/Block loads will be approximately 2,637 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 2022 was 6,581 annual average megawatts. The aggregate amount of power loads to be served at Tier 1 PF Rates has been estimated at 6,515 annual average megawatts for Fiscal Year 2023 and 6,755 annual average megawatts for Fiscal Year 2024.

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 173 annual average megawatts of Tier 2 Loads in Fiscal Year 2023, approximately 210 annual average megawatts in Fiscal Year 2024, and approximately 395 annual average megawatts in Fiscal Year 2025. Tier 2 Loads were 54 annual average megawatts in Fiscal Year 2020, 63 annual average megawatts in Fiscal Year 2021, and 157 annual average megawatts in Fiscal Year 2022. 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 are approximately $33.65 per megawatt hour and average Tier 1 PF Rates are approximately $34.93 per megawatt hour (exclusive of any rate adjustment mechanisms). See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2022-2023." Under the 2024-2025 Initial Rate Proposal, average Tier 2 PF Rates are proposed to be approximately $61.50 per megawatt hour and average Tier 1 PF Rates are proposed to be approximately $34.69 per megawatt hour. 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 proposed Tier 2 Rate increase for the 2024-2025 Rate Period 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 18 annual average megawatts in Operating Year 2024, and an energy deficit of approximately 289 annual average megawatts in Operating Year 2025, assuming Firm Water and transmission line losses. Between Operating Years 2024 and 2033, Bonneville forecasts annual planning deficits that vary between 18 annual average megawatts (in Operating Year 2024) 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. Bonneville is seeking public comment on this plan and expects to publish the plan in the spring of 2023.

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"), concluded that Bonneville, in addition to existing resources, can satisfy much of its expected supply obligations with electric power conservation, short-term power purchases from wholesale power markets, and demand response programs which shift or shed electricity demand to provide flexibility in power markets, helping to balance the grid.

*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 2022-2023 Rate Period, Bonneville forecasts that it will achieve up to 75 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 six years of the settlement agreement term, the schedule of aggregate program benefits for the Regional IOUs ranges from $259 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 2022 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 2020 through 2022.

**Fish and Wildlife Financial Impacts by Type**
**(Unaudited)[(2)]**
**(Fiscal Years 2020-2022, dollars in millions)**

| | 2022 | 2021 | 2020 |
|---|---|---|---|
| **Direct Costs** | $ 442 | $ 443 | $ 428 |
| **Estimated Operational Impacts[(1)]:** | | | |
| **Replacement Power Purchase Costs** | 238 | 111 | 150 |
| **Foregone Power Revenues** | 252 | 191 | 33 |
| **Total Fish and Wildlife** | **$ 932** | **$ 745** | **$ 611** |

(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, and the litigation stay was extended until August 31, 2023 at the District Court and until September 8, 2023 in the Ninth Circuit Court.

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.

The Final CRSO EIS and 2020 Columbia River System Biological Opinions are 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 2024-2025 Initial Rate Proposal, 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—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2024-2025" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2022-2023."

*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 2022, Bonneville was responsible for approximately $1.1 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 $103 million through Fiscal Year 2027. This would bring the total amount of Bonneville's Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation to approximately $1.2 billion by the end of Fiscal Year 2027. The amounts ultimately appropriated under the Columbia River Fish Mitigation program (through Fiscal Year 2027 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 2028, 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 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 current commitment through 2025 for the Columbia Basin Fish Accords is approximately $564 million. This total includes approximately $155 million in remaining commitments from the prior agreements and $409 million in additional commitments from the most recent extensions. 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).

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 approximately 197 megawatts of power are 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). In May 2022, Congress directed the Corps to complete a disposition study of the power purpose at the Willamette Project no later than December 2023. 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 its Willamette River Basin Flood Control Project Biological Opinion (the "2008 Willamette BiOp") in 2008. 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 reservoir drawdowns at Cougar, Detroit, 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 are expected 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 and Willamette EIS are 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.

<u>Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville</u>. 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 $96 million, $91 million, and $112 million in Fiscal Years 2020, 2021, and 2022, 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 2022, Integrated Program expense was $280 million, and Federal System capital investment was $16 million. Bonneville forecasts that Fiscal Year 2023 Integrated Program expense and Federal System capital investments will be $286 million and $43 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 2022-2023*

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's Final 2022-2023 Rates for power and transmission rates of general applicability and FERC has granted final approval thereof. The final Tier 1 PF Rates for the 2022-2023 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 2.5 percent from the prior average rates to $34.93 per megawatt hour. Under the Final 2022-2023 Rates, average Tier 2 PF Rates (which apply to certain incremental loads that Preference Customers require Bonneville to meet) are six percent higher than in the prior rate period, increasing to $33.65 per megawatt hour. 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—Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products."

The Final 2022-2023 Rates for Power Services continue the availability of the RDC, which has triggered for application to certain power rates in Fiscal Year 2022 and for certain power and transmission rates in Fiscal Year 2023. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Under the Final 2022-2023 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 $20 per megawatt hour and $29 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2022. 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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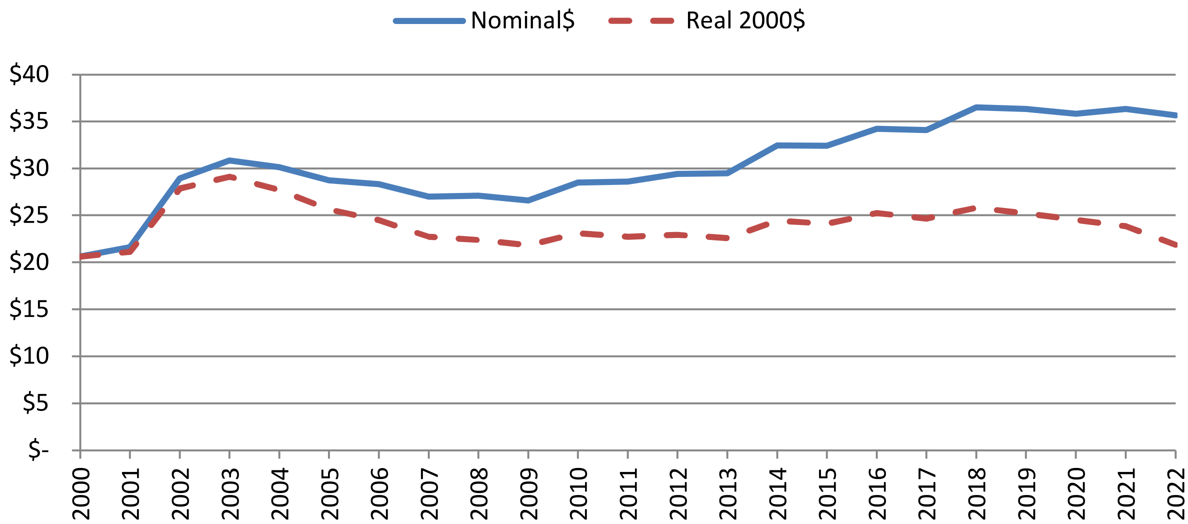
**Historical Average PF Preference Rates**

**Nominal (Actual) and Real (Inflation-Adjusted) Average PF Preference Rate Levels, Per Megawatt Hour, Fiscal Years 2000—2022**




*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 $1.1 billion in revenues from the sale of transmission and related services, or approximately 23 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 2022.

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 2022-2023), 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 $34.93 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 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 2022-2023 Rates, Bonneville expects to make transmission system investments in Fiscal Years 2023 through 2032 averaging approximately $543 million annually. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program" and "—Bonneville's Non-Federal Debt."

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 is beginning a proceeding to improve the efficiency of this process. 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 $21 million in Fiscal Year 2022. Bonneville estimates that the transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments will be $18 million in Fiscal Year 2023 and approximately $25 million in Fiscal Year 2024.

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.

To date, Bonneville has received approximately 2,000 perfected administrative tort claims under the Federal Tort Claims Act for damage related to the September 2020 wildfires totaling approximately $2 billion in the aggregate. 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."

**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 2022-2023 Rates for Transmission Services reflect an increase of 5.4 percent, when compared to average rates in effect in the prior rate period. The Final 2022-2023 Rates for Transmission Services continue the availability of the RDC, which has triggered for application to Fiscal Year 2023 Transmission Services rates. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates."

**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 2022. The table also notes the type of entity for each customer.

**Transmission Services' Ten Largest Customers By Sales[(1)]**
**(Percentage of Transmission Services' Sales Revenue in Fiscal Year 2022)**

| Customer Name (Class) | Approximate % of Sales |
|---|---|
| Puget Sound Energy Inc. (Regional IOU) | 11% |
| PacifiCorp (Regional IOU) | 10% |
| Portland General Electric Company (Regional IOU) | 9% |
| Powerex Corp. (Power Marketer) | 9% |
| City of Seattle, City Light Dept. (Preference Customer) | 5% |
| Snohomish County PUD No. 1 (Preference Customer) | 5% |
| Avangrid Renewables LLC (Wind Developer) | 4% |
| Morgan Stanley Capital Group Inc. (Power Marketer) | 3% |
| Clark Public Utilities (Preference Customer) | 2% |
| Umatilla Electric Cooperative (Preference Customer) | 2% |

(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 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. 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 sixteenth round of negotiations was held in March 2023. During this round, the United States and Canada discussed post-2024 flood risk management, Canada's desire for more operational flexibility, hydropower coordination, and mechanisms for achieving ecosystem objectives.

### 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 Power Marketing Administrations (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. On December 15, 2021, President Biden signed legislation raising the debt ceiling by $2.5 trillion to $31.4 trillion. On January 19, 2023, the United States reached the debt ceiling and the United States Treasury began taking "extraordinary measures" that it expects will allow the United States to continue paying its obligations until early to mid-summer 2023. Bonneville does not expect the extraordinary measures to impact Bonneville's operations but 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.

**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.

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 Bonneville 2018–2023 Strategic Plan by conserving resources, increasing operational efficiencies and lengthening the lifespan of assets which ultimately leads to strengthened financial health and competitiveness. A 2024-2028 Strategic Plan is under development and expected to be released in the spring of 2023.

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.

*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 environmental impacts of the federal dams and transmission system, and provide compliance with a host of environmental 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, and, if so, how they 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.

Bonneville believes that direct cost impacts on Bonneville of initiatives to reduce carbon emissions will be somewhat limited because the Federal System's generating projects are not carbon-emitting generators: the Federal System's resources are either hydro- or nuclear-based generation, with a small amount of wind-based purchases. However, state programs do attribute carbon emissions to Bonneville's system as a result of Bonneville's market purchases since these market purchases do not identify the generator that produced the power at the time of transaction. Instead, state carbon programs assign a default carbon emissions rate to market purchases. Market purchases represent between 3-12 percent of Bonneville's annual fuel mix. Given that these are the only carbon emissions attributed to Bonneville's system, Bonneville's overall emissions rate is extremely low. On average, Bonneville's system has historically been 95 percent carbon-free.

Given the predominance of non-carbon-emitting 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. 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."

In Fiscal Year 2022, Bonneville's Sustainability Office completed an initial analysis of the impacts of climate change on several critical systems. 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 snow pack. 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 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.

Consistent with President Biden's Executive Order 14057 on catalyzing American clean energy industries and jobs through Federal sustainability and accompanying Federal Sustainability Plan (collectively referred to as "the 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's next Strategic Plan update will frame carbon among the agency's strategic priorities, outlining goals and objectives for Bonneville to address in the coming years. As part of these goals, Bonneville intends to analyze carbon-free resource and purchase options and pursue cost-effective carbon free options in future acquisitions; continue to review its greenhouse gas ("GHG") accounting practices and look for opportunities to better reflect system sales in state GHG accounting constructs; and consider the emissions impacts to the Federal System as it makes future policy decisions. See “BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville Financial Operations.”

*Diversity and Inclusion in the Bonneville Workforce*

In 2020, Bonneville developed a Culture Strategy and added a fifth strategic goal to Bonneville’s 2018–2023 Strategic Plan: Value People and Deliver Results. The Culture Strategy is a two-year roadmap that outlines an intentional investment in the Bonneville community to better deliver on Bonneville’s 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 every two years, or just prior to each rate case, and is the public review for the costs that will be recovered through rates the following two-year 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—Current Bonneville Power and Transmission Rates.”

**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 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 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.

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.

### 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.

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. In order 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 466 megawatts of utility scale solar generation facilities are now interconnected to the Federal Transmission System and approximately 147 megawatts are currently in Bonneville's balancing authority area. By the end of Fiscal Year 2023, Bonneville expects that it will integrate into the Federal Transmission System an additional 202 megawatts of solar resources (bringing the total solar integrated into the Federal Transmission System to 668 megawatts).

**Regional and Market Initiatives**

*Day Ahead Markets in the West*

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 that it will commit resources to support and evaluate Phase 1 development of Markets+. Bonneville estimates that its costs associated with Phase 1 will be between $1.5 million and $2.2 million, depending on how many Western load-serving entities and balancing authorities participate. Bonneville has not made a decision to join Markets+ as a market participant and would hold a public process before deciding to participate in any market. Bonneville participated in the first Markets+ Participants' Executive Committee meeting in April 2022 and voted to approve the governance structure and associated working group scope and participants.

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.

*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.

Over the past three years, entities in the West have come together through an initiative facilitated by the Western Power Pool 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 will use 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 will provide another resource 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 the Western Power Pool 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.

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, 2022, Bonneville had repaid $17.6 billion of principal of the Federal System investment and had approximately $1.6 billion principal amount outstanding with regard to such appropriated investments and $5.7 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 January 2018, Bonneville published a 5-year Strategic Plan (2018–2023) 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 Strategic Plan sets forth the following four strategic goals: (i) strengthen financial health; (ii) modernize assets and system operations; (iii) provide competitive power products and services; and (iv) meet transmission customer needs efficiently and responsively. In October 2020, Bonneville published a progress update to the Strategic Plan that documented Bonneville's achievements in the implementation of the 2018-2023 Strategic Plan and formally integrated a new fifth strategic goal ("Value people and deliver results") into the strategy. The 2024-2028 Strategic Plan is under development and expected to be released in the spring of 2023.

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 that total amount of revenue financing 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 health objectives. At the end of Fiscal Year 2022, Bonneville's Days Cash on Hand was 233 days, significantly exceeding the minimum threshold outlined in the Financial Plan. At the end of the Fiscal Year 2022, the agency debt-to-asset ratio was 82 percent. In the Final 2022-2023 Rates, both power and transmission rates include a planned amount of revenue financing in each of the two fiscal years of the rate period ($40 million for power and $40 million for transmission), which is contributing to improvement of the overall debt-to-asset ratio. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates."

### 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 $5.7 billion were outstanding as of the end of Fiscal Year 2022. 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 2022, the total amount of bonds outstanding as of the end of Fiscal Year 2022 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 $12.4 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 2022, the interest rates on the outstanding bonds ranged from 0.2 percent to 5.9 percent with a weighted average interest rate of approximately 3.0 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2022, Bonneville's outstanding bonds issued to the United States Treasury included $626 million in variable rate bonds at an average interest rate of 2.88 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, 2022, aggregate Non-Federal Debt outstanding was approximately $7.4 billion. By way of comparison, as of September 30, 2022, 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 $5.7 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.

*Net Billed Bonds*

Net Billed Projects represent the largest single component of Non-Federal Debt: $5.1 billion out of a total of $7.4 billion aggregate Non-Federal Debt, as of September 30, 2022.

The amounts potentially subject to net billing are substantial. The debt service on the Net Billed Bonds in Fiscal Year 2022 was $185 million. In addition, the operations and maintenance expense for the Columbia Generating Station in Fiscal Year 2022 was $276 million. For more details related to the Columbia Generating Station, see the Official Statement under "ENERGY NORTHWEST—The Columbia Generating Station."

As discussed in the Official Statement under "ENERGY NORTHWEST—Energy Northwest Indebtedness," since 2001, Energy Northwest and Bonneville have worked together to refinance certain maturities of the Net Billed Bonds so that the weighted average maturities more closely match the originally expected useful lives of the related Net Billed Project facilities.

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 as key to Bonneville's long-term financial health. 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 $1.5 billion from July 2023 through June 2034. See the Official Statement under "ENERGY NORTHWEST—The Columbia Generating Station—Capital Improvements." 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 $2.9 billion of Net Billed Bonds to: (i) refinance certain Net Billed Bond debt through 2030 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. A portion of the Series 2023-A Bonds will refinance Net Billed Bonds. In Fiscal Year 2022, Energy Northwest issued approximately $295 million of Net Billed Bonds under the Regional Cooperation Debt approach which enabled Bonneville to prepay approximately $334 million of outstanding Federal Debt over the amounts that Bonneville was scheduled to repay in Fiscal Year 2022. See the Official Statement under "ENERGY NORTHWEST—Energy Northwest Indebtedness."

*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 Port of Morrow, Oregon (the "Port of Morrow").

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, 2022. 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 March 2025, which Bonneville expects to fund from publicly-issued lease-purchase bonds prior to maturity. It is possible that the Port of Morrow, IERA, or others could issue such publicly-offered bonds. No official action by any third party has been taken to authorize such additional bonds.

*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, 2022, outstanding Non-Federal Debt associated with electric power prepayments was $163 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, 2022, outstanding Non-Federal Debt for generating resource acquisitions was $62 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 2020 through 2022. Any discrepancies in totals for figures portrayed in this table are due to rounding.

**Non-Federal and Federal Debt, Fiscal Years 2020-2022**
**(Dollars in millions)**

**Non-Federal and Federal Debt Outstanding**

| **Projects Financed with Non-Federal Debt** | **2022** | **2021** | **2020** |
|---|---|---|---|
| **Non-Federal Generation** | | | |
| Columbia Generating Station | $3,296 | $3,247 | $3,130 |
| Cowlitz Falls Project | 56 | 61 | 65 |
| **Terminated Generation** | | | |
| Nuclear Project No. 1 | 824 | 809 | 792 |
| Nuclear Project No. 3 | 950 | 930 | 912 |
| Northern Wasco Hydro Project | 5 | 7 | 8 |
| Lease-Purchase Program | 1,957 | 2,029 | 2,098 |
| Finance Lease/Other Financial Liability | 118 | 114 | 108 |
| Customer prepaid power purchases | 163 | 186 | 207 |
| **Total Non-Federal Debt** | $7,369 | $7,383 | $7,320 |
| **Federal Debt** | | | |
| Borrowings from U.S. Treasury | 5,679 | 5,629 | 5,649 |
| Federal appropriations | 1,243 | 1,233 | 1,213 |
| Federal appropriations (not yet scheduled for repayment) | 398 | 370 | 331 |
| **Total Federal Debt** | $7,320 | $7,232 | $7,193 |
| **Total Debt** | **$14,689** | **$14,615** | **$14,513** |

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 Net Billed Project costs (including debt service on the Series 2023-A Bonds and other Net Billed Bonds) 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 to meet debt service on the Series 2023-A Bonds and other Net Billed Bonds.

**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 2018-2022. 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)**

| | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
|---|---|---|---|---|---|---|
| Transmission(2) | $411 | $432 | $371 | $413 | $497 | **$2,124** |
| Federal System Hydro | 199 | 200 | 178 | 203 | 192 | **972** |
| Fish and Wildlife | 31 | 22 | 40 | 41 | 16 | **150** |
| Facilities, Information Technology, Security(2) | 14 | 10 | 20 | 23 | 16 | **83** |
| **Total** | **$655** | **$664** | **$609** | **$680** | **$721** | **$3,329** |

(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 2018 through Fiscal Year 2022. 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)**

| | 2018 | 2019 | 2020 | 2021 | 2022 | Total |
|---|---|---|---|---|---|---|
| Borrowing from United States Treasury | $498 | $425 | $520 | $617 | $606 | **$2,666** |
| Lease-Purchases(2) | 77 | 37 | 38 | 22 | - | **174** |
| Projects Funded in Advance | 65 | 106 | 25 | 15 | 35 | **246** |
| Revenue Funding | 15 | 15 | 26 | 26 | 80 | **162** |
| Electric Power Prepayments(3) | - | 81 | - | - | - | **81** |
| **Total** | **$655** | **$664** | **$609** | **$680** | **$721** | **$3,329** |

(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 Bonneville's 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. However, in Fiscal Year 2023 Bonneville made a determination that did involve substantial long-term commitments for new capital investments. In March 2023, after over a decade of evaluation, Bonneville determined not to proceed as joint owners with two other regional utilities with the construction of a new transmission line and related facilities in portions of Oregon and southern Idaho. Through March 2023, Bonneville had recorded approximately $31 million as construction work in progress related to preliminary design and permitting costs for the proposed transmission line. On March 24, 2023. Bonneville reached an agreement with one of the partnering regional utilities to sell and transfer Bonneville's share of the permitting interest, enabling the remaining two utilities to proceed with design and construction of the transmission line. The approximately $31 million value of Bonneville's permitting interest will be recovered, subject to certain conditions precedent, over 20 years following the energization of the line. Adjusted to reflect the time value of money and project risks, the permitting interest transfer results in a $28 million reduction to net revenues in Fiscal Year 2023.

In connection with developing the 2024-2025 Initial Rate Proposal, Bonneville has assumed the capital spending levels shown in the table that follows. These spending levels reflect the preliminary outcome of Bonneville's capital prioritization process.

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

| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission | $525 | $517 | $528 | $537 | $704 | $663 | $533 | $469 | $431 | $519 | **$5,426** |
| Fed System Hydro | 211 | 270 | 276 | 282 | 288 | 295 | 302 | 309 | 316 | 324 | **2,873** |
| Fish and Wildlife | 43 | 41 | 41 | 29 | 16 | 15 | 15 | 15 | 15 | 15 | **245** |
| Facilities, Information Technology, Security | 97 | 147 | 131 | 96 | 69 | 75 | 73 | 72 | 74 | 74 | **908** |
| AFUDC(1) | 15 | 27 | 27 | 28 | 28 | 28 | 28 | 28 | 28 | 28 | **265** |
| **Total** | **$891** | **$1,002** | **$1,003** | **$972** | **$1,105** | **$1,076** | **$951** | **$893** | **$864** | **$960** | **$9,717** |

(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 Generation Station. Energy Northwest has developed a long-term capital investment strategy for the Columbia Generation 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 $1.6 billion in additional capital requirements from July 2022 through June 2033. 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—Net Billed Bonds." 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 2043.

**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 \$235 million, \$143 million, and \$31 million, respectively, in Fiscal Year 2022.

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 \$407 million to \$736 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 expects that it will renew and extend the direct funding operations and maintenance agreement with the Corps in Fiscal Year 2023 prior to its expiration date. 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 2022 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 cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2023-A Bonds; payments, if any, under the 1989 Letter Agreement; payments, if any, under the Direct Pay Agreements; 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 cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2023-A Bonds; payments, if any, under the 1989 Letter Agreement; payments, if any, under the Direct Pay Agreements; 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 the Official Statement under "SECURITY FOR THE NET BILLED BONDS" and "—Direct Pay Agreements" in this Appendix A.

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—Net Billed Bonds" 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 $21 million in Fiscal Year 2022. Bonneville estimates that transmission service credit offsets will be $18 million in Fiscal Year 2023. 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 payments under the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements.

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 2022, approximately $1.4 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 $445 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 2022." 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 2022, Bonneville had $1.5 billion in RAR and a $750 million short-term credit facility (available to meet certain expenses) with the United States Treasury. 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—Current Bonneville Power and Transmission Rates" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2022-2023." 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 2022, Total Financial Reserves were approximately $1.8 billion ($146 million of which represents Deferred Borrowing). See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "—Fiscal Year 2022

Financial Results," and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2022-2023."

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 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 2018-2022**
**(Unaudited)[1]**
**(Dollars in millions)**

| Fiscal Year | Total Financial Reserves | Reserves Available for Risk | U.S. Treasury Short-Term Line | Days Liquidity on Hand |
|---|---|---|---|---|
| 2018 | 840 | 551 | 750 | 254 |
| 2019 | 773 | 484 | 750 | 222 |
| 2020 | 889 | 708 | 750 | 295 |
| 2021 | 1,056 | 825 | 750 | 284 |
| 2022 | 1,834 | 1,511 | 750 | 380 |

(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 2022-2023 Rates, Bonneville assumed that revenues from net seasonal surplus energy sales would average approximately $363 million per fiscal year of the rate period, assuming average streamflow. For reference, $363 million is approximately eight percent of Bonneville total operating revenues of approximately $4.7 billion (Fiscal Year 2022).

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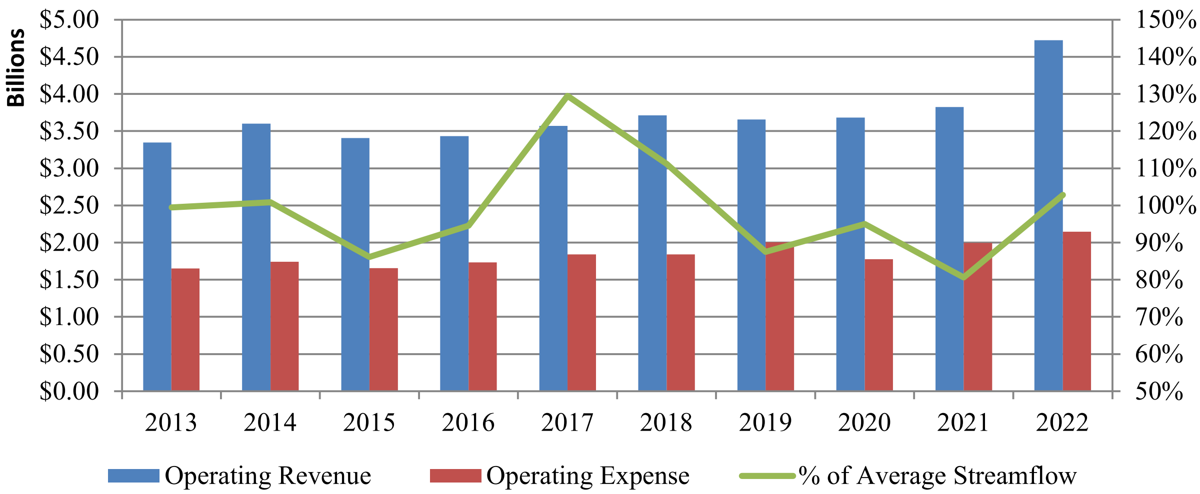
**Historical Federal System Operating Revenue and Operating Expense**
**Compared to Historical Streamflow**
**($ in thousands)**




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 2022, Bonneville made $37 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—Net Billed Bonds."

**Historical Federal System Financial Data**

Federal System historical financial data for Fiscal Years 2020 through 2022 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.

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

| **As of Sept. 30 – Dollars in millions** | **2022** | **2021** | **2020** |
|---|---|---|---|
| Operating Revenues: | | | |
| Sales of electric power — | | | |
| Sales within the Northwest Region — | | | |
| Northwest Publicly-Owned Utilities [1] | $2,144 | $2,130 | $2,118 |
| Direct Service Industrial Customers | 4 | 4 | 4 |
| Northwest Investor-Owned Utilities | 304 | 116 | 49 |
| Sales outside the Northwest Region [2] | 1,043 | 491 | 434 |
| Book-outs [3] | (63) | (57) | (45) |
| Total Sales of Electric Power | 3,432 | 2,684 | 2,560 |
| Transmission Sales [4] | 1,119 | 1,010 | 985 |
| Fish Credits and other Revenues [5] | 171 | 129 | 139 |
| Total Operating Revenues | 4,722 | 3,823 | 3,684 |
| Operating Expenses: | | | |
| Bonneville O&M [6] | 1,212 | 1,161 | 1,118 |
| Purchased Power [3] | 359 | 248 | 124 |
| Corps, Reclamation, and Fish & Wildlife Service O&M [7] | 410 | 404 | 411 |
| Non-Federal entities O&M — net billed [8] | 274 | 308 | 256 |
| Non-Federal entities O&M — non-net billed [9] | 33 | 30 | 30 |
| Total Operations and Maintenance | 2,288 | 2,151 | 1,939 |
| Depreciation, Amortization and Accretion | 841 | 826 | 819 |
| Residential Exchange [10] | 267 | 250 | 250 |
| Total Operating Expenses | 3,396 | 3,227 | 3,008 |
| Net Operating Revenues | 1,326 | 596 | 676 |
| Interest Expense and Other Income/Expense: | | | |
| Appropriated Funds | 41 | 44 | 45 |
| Long-term debt – net billed | 207 | 221 | 244 |
| Long-term debt – non-net billed | 224 | 226 | 241 |
| Capitalization Adjustment [11] | (65) | (65) | (65) |
| Other (income)/expense, net[12] | (20) | (202) | (7) |
| Allowance for funds used during construction | (25) | (26) | (28) |
| Net Interest Expense and Other Income/Expense[13] | 362 | 198 | 430 |
| Net Revenues/(Expenses) | **$ 964** | **$ 398** | **$ 246** |
| Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return) | 10,861 | 9,667 | 10,240 |

(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 $96 million, $91 million, and $112 million in Fiscal Years 2020, 2021, and 2022, 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 2022, 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 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 2022 Audited Financial Statements).

*Fiscal Year 2020*

In Fiscal Year 2020, Bonneville made its scheduled United States Treasury payments on time and in full for the 37th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $889 million, which is an increase of approximately 15 percent from the prior fiscal year.

At the end of Fiscal Year 2020, aggregate Bonneville RAR was $708 million, an increase of approximately 46 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $435 million, an increase of $232 million from the prior fiscal year-end balance of $203 million, and RAR for Transmission Services operations was $273 million, a decrease of $8 million from the prior fiscal year-end balance of $281 million.

In Fiscal Year 2020, Federal System net revenues were $246 million, a decrease of approximately $2 million from net revenues of $248 million in Fiscal Year 2019.

In Fiscal Year 2020, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $3.5 billion, which is about $51 million more than the prior fiscal year. Power Services' gross sales increased $6 million, or less than one percent, in Fiscal Year 2020 compared to Fiscal Year 2019, primarily due to an $82 million increase in revenues from seasonal surplus sales due to above-average hydro power generation. This increase was almost entirely offset by a $76 million decrease in firm power sales primarily due to lower power load requirements. 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 2020 runoff volume at The Dalles Dam was 102 MAF. The full Fiscal Year 2020 volume finished at 126 MAF, an increase of 10 MAF from Fiscal Year 2019, and below the historical average of 134 MAF.

In Fiscal Year 2020, Transmission Services sales increased $45 million compared to Fiscal Year 2019, primarily due to the 3.6 percent average transmission rate increase that went into effect on October 1, 2019. See "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

In Fiscal Year 2020, United States Treasury credits decreased $2.7 million compared to Fiscal Year 2019, primarily due to increased streamflow resulting in lower replacement power purchases.

In Fiscal Year 2020, Operating expense decreased $192 million, or approximately six percent, compared to Fiscal Year 2019. In Fiscal Year 2020, Operations and maintenance expense decreased $72 million, or three percent, from the prior fiscal year primarily due to a $63 million decrease in Columbia Generating Station plant costs since Fiscal Year 2020 was not a refueling year (refueling and maintenance expense are typically higher in refueling years). In Fiscal Year 2020, Purchased Power expense, including the effects of bookouts, decreased $175 million, or approximately 59 percent, compared to Fiscal Year 2019 mainly due to: (i) a $36 million decrease in Purchased Power that Bonneville needed to serve its loads in Fiscal Year 2020 compared to periods of extremely cold weather in Fiscal Year 2019 that increased demand for energy during times of high market prices and limited supply, (ii) a $100 million decrease in the amount owed to BC Hydro under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2019 when it released additional water from the Arrow Dam in Canada, and (iii) a shift to meet Tier 2 Loads with surplus power rather than with purchased power (in Fiscal Year 2019, Bonneville had made $41 million of power purchases to serve Tier 2 loads).

In Fiscal Year 2020, Non -Federal Projects Debt Service was zero due to changes in reporting of Non -Federal Project costs beginning in Fiscal Year 2020. For additional details regarding these changes, see Appendix B-1 to the Official

Statement (Note 1 to the Fiscal Year 2021 Audited Financial Statements). For comparison purposes, in Fiscal Year 2020, Bonneville's contractual commitments related to Non-Federal Projects Debt Service were $293 million, an increase of $60 million compared to $233 million for Fiscal Year 2019. This increase was primarily due to the receipt of lower revenues in Fiscal Year 2020 by Energy Northwest for the sale of its nuclear fuel that is treated as an offset to debt service for outstanding debt for the Columbia Generating Station. The impact of the lower revenues received by Energy Northwest for the sale of its nuclear fuel was partially offset by decreased debt service for outstanding debt for the Columbia Generating Station in Fiscal Year 2020 when compared to Fiscal Year 2019.

In Fiscal Year 2020, Depreciation, Amortization, and Accretion increased $288 million primarily due to $216 million and $33 million increases to the amortization of nonfederal generation assets and accretion expense, respectively. This increase is also affected by the changes in reporting of Non-Federal Projects Debt Service as mentioned above.

In Fiscal Year 2020, total Net Interest Expense and Other Income/Expense, increased $221 million compared to Fiscal Year 2019, primarily due a $217 million increase in Interest Expense related to changes in reporting of Non-Federal Projects Debt Service costs beginning in Fiscal Year 2020 to record interest expense related to Non-Federal Projects as Interest Expense rather than as part of Non-Federal Projects Debt Service.

**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 | 2022 | 2021 | 2020 |
|---|---|---|---|
| Total Operating Revenues | $4,722 | $3,823 | $3,684 |
| Less: Operating Expenses[1] | 2,144 | 1,996 | 1,778 |
| Net Funds Available to meet Non-Federal Debt Service Obligations | 2,578 | 1,827 | 1,906 |
| Less: Non-Federal Debt Service Obligations | | | |
| Non-Federal Projects[2] | 194 | 171 | 293 |
| Lease-Purchase Program[3] | 132 | 134 | 138 |
| Electric Power Prepayments [4] | 31 | 31 | 31 |
| Total Non-Federal Debt Service Obligations | 357 | 336 | 462 |
| Revenue Available for Treasury | 2,221 | 1,491 | 1,444 |
| Non-Federal Debt Service Coverage Ratio[5] | 7.2x | 5.4x | 4.1x |
| Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[6] | 1.9x | 1.6x | 1.6x |
| Amount Allocated for Payment to Treasury[7]: | | | |
| Corps and Reclamation O&M[8] | 410 | 404 | 411 |
| Net Interest Expense and Other Income/Expense[9] | 362 | 198 | 430 |
| Non-Federal Projects[2, 9] | (187) | (24) | (231) |
| Lease-Purchase Program[3, 9] | (59) | (61) | (66) |
| Electric Power Prepayments[4, 9] | (8) | (9) | (10) |
| Capitalization Adjustment[10] | 65 | 65 | 65 |
| Allowance for Funds Used During Construction [11] | 15 | 12 | 10 |
| Amortization of Federal Principal[12] | 694 | 806 | 471 |
| Total Amount Allocated for Payment to Treasury[7] | 1,292 | 1,391 | 1,080 |

(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 2020, 2021, and 2022 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 2022, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $31 million. Of this amount, $8 million is accounted for as Net Interest Expense and $23 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:

**Total Operating Revenues-Operating Expense (Footnote 1)**

**Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments**

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

**Total Operating Revenues**

**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 2020, 2021, and 2022 were $736 million, $1.05 billion, and $951 million 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 2020, 2021, and 2022. 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 $334 million in Federal Obligations in Fiscal Year 2022, $332 million in Fiscal Year 2021, and $20 million in Fiscal Year 2020, 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. In Fiscal Years 2011-2013, which immediately preceded the commencement of the Regional Cooperation Debt initiative, the Non-Federal Debt Service Coverage Ratio ranged between 2.2x and 2.5x. Bonneville can provide no assurance regarding future debt service coverage ratios. See "—Bonneville's Non-Federal Debt—Net Billed Bonds."

(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 Three Months ended December 31, 2022

Total operating revenues were $1.1 billion through the first quarter of Fiscal Year 2023 ("Fiscal Year 2023 First Quarter"), an increase of $59 million as compared to operating revenues for the three months ended December 31, 2021 ("Fiscal Year 2022 First Quarter"). Consolidated gross sales for Power and Transmission Services, including the effect of bookouts, increased by $38 million through Fiscal Year 2023 First Quarter compared to consolidated gross sales through Fiscal Year 2022 First 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 were $761 million through Fiscal Year 2023 First Quarter, an increase of $55 million as compared to Fiscal Year 2022 First Quarter. Seasonal surplus energy sales increased by $66 million primarily due to higher short-term energy market prices that Bonneville obtained for the sale of seasonal surplus energy over amounts assumed in the rate case for the current period. In addition, firm power sales decreased by $11 million. The decrease in firm power sales is primarily due to the Power Reserves Distribution Clause rate reduction that is being applied as a credit to Power rates from December 2022 through September 30, 2023 (that has the effect of reducing power revenues by $41 million). Partially offsetting the decrease in power rates due to the Power Reserves Distribution Clause is a $28 million increase in firm power sales due to extreme cold weather resulting in higher loads in Fiscal Year 2023 First Quarter.

Transmission Services sales increased by $16 million through Fiscal Year 2023 First Quarter as compared to Fiscal Year 2022 First Quarter, primarily due to (i) a $12 million increase in the sale of point-to-point long-term transmission service, and (ii) a $6 million increase in revenues related to Bonneville's participation the EIM. Bonneville joined the EIM in May 2022 and there were no revenues related to EIM in Fiscal Year 2022 First Quarter.

United States Treasury credits for fish and wildlife mitigation increased by $19 million due to decreased streamflow through Fiscal Year 2023 First Quarter which led to an increase in purchased power expense primarily related to higher market prices.

Through Fiscal Year 2023 First Quarter, total operating expenses were $1.1 billion, a $330 million increase when compared to Fiscal Year 2022 First Quarter.

Operations and maintenance expense increased by $38 million primarily due to: (i) a $12 million increase in Columbia Generating Station plant costs since Fiscal Year 2023 is a refueling year and maintenance expense is typically higher in refueling years, (ii) an $11 million increase in fish and wildlife expenses, (iii) an $8 million increase in settlement charges related to Bonneville's participation in the EIM (Bonneville joined the EIM in May 2022 and there were no expenses related to EIM in Fiscal Year 2022 First Quarter), and (iv) an $8 million net increase to various other Transmission Services and Power Services program costs. Purchased power expense, including the effects of bookouts, increased by $291 million primarily due to a $224 million increase in power purchases due to higher market prices that Bonneville paid for its purchased power during cold weather experienced in Fiscal Year 2023 First Quarter. This amount is partially offset by a $67 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.

Total Interest Expense and Other Income, Net, decreased $9 million in Fiscal Year 2023 First Quarter when compared to the same period in Fiscal Year 2022. Interest Expense increased by $6 million related to outstanding variable debt owed to the United States Treasury. Interest Income increased by $15 million in Fiscal Year 2023 First Quarter when compared to the same period in Fiscal Year 2022 due to an increase in short-term investments in United States Treasury securities and higher interest rates earned on such investments.

For further information regarding Fiscal Year 2023 First Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE THREE MONTHS ENDED DECEMBER 31, 2022."

## 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 federal government is currently engaged in long-term comprehensive solution discussions. 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).

**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.

**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. Plaintiffs seek: (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 is scheduled for June 8, 2023.

**Fiscal Year 2023 Power RDC Challenge**

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 implementation of the Power RDC, which was issued on January 6, 2023. For details related to the Power RDC, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates." Plaintiffs seek: (i) a decision to set aside Bonneville's 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.

**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.

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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 (FCRPS), (the "Company"), which comprise the combined balance sheets as of September 30, 2022 and 2021, 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, 2022 and 2021, 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 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 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 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 always detect

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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 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 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

PricewaterhouseCoopers LLP
November 1, 2022

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

(Millions of Dollars)

| | 2022 | 2021 |
|---|---|---|
| **Assets** | | |
| **Utility plant and nonfederal generation** | | |
| Completed plant | **$ 21,300.0** | $ 20,758.8 |
| Accumulated depreciation | **(7,994.8)** | (7,758.6) |
| Net completed plant | **13,305.2** | 13,000.2 |
| Construction work in progress | **1,316.7** | 1,342.8 |
| **Net utility plant** | **14,621.9** | 14,343.0 |
| Nonfederal generation | **3,404.6** | 3,527.7 |
| **Net utility plant and nonfederal generation** | **18,026.5** | 17,870.7 |
| **Current assets** | | |
| Cash and cash equivalents | **1,663.0** | 1,207.9 |
| Short-term investments in U.S. Treasury securities | **500.8** | - |
| Accounts receivable, net of allowance | **41.7** | 18.3 |
| Accrued unbilled revenues | **458.2** | 301.3 |
| Materials and supplies, at average cost | **109.4** | 109.5 |
| Prepaid expenses | **49.0** | 39.5 |
| **Total current assets** | **2,822.1** | 1,676.5 |
| **Other assets** | | |
| Regulatory assets | **4,452.2** | 4,781.5 |
| Nonfederal nuclear decommissioning trusts | **414.6** | 515.2 |
| Deferred charges and other | **237.2** | 214.6 |
| **Total other assets** | **5,104.0** | 5,511.3 |
| **Total assets** | **$ 25,952.6** | $ 25,058.5 |

***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)

| | 2022 | 2021 |
|---|---|---|
| **Capitalization and Liabilities** | | |
| **Capitalization and long-term liabilities** | | |
| Accumulated net revenues | **$ 5,859.6** | $ 4,912.6 |
| Debt | | |
| Federal appropriations | **1,640.9** | 1,602.8 |
| Borrowings from U.S. Treasury | **5,384.7** | 5,049.9 |
| Nonfederal debt | **6,901.4** | 6,932.2 |
| **Total capitalization and long-term liabilities** | **19,786.6** | 18,497.5 |
| **Commitments and contingencies (See Note 14 to 2022 Audited Financial Statements)** | | |
| **Current liabilities** | | |
| Debt | | |
| Borrowings from U.S. Treasury | **294.0** | 579.0 |
| Nonfederal debt | **468.5** | 451.0 |
| Accounts payable and other | **725.4** | 668.7 |
| **Total current liabilities** | **1,487.9** | 1,698.7 |
| **Other liabilities** | | |
| Regulatory liabilities | **1,565.6** | 1,552.6 |
| IOU exchange benefits | **1,514.0** | 1,722.2 |
| Asset retirement obligations | **964.3** | 929.2 |
| Deferred credits and other | **634.2** | 658.3 |
| **Total other liabilities** | **4,678.1** | 4,862.3 |
| **Total capitalization and liabilities** | **$ 25,952.6** | $ 25,058.5 |

***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)

| | 2022 | 2021 | 2020 |
|---|---|---|---|
| **Operating revenues** | | | |
| Sales | **$ 4,604.6** | $ 3,727.8 | $ 3,583.6 |
| U.S. Treasury credits | **116.9** | 95.2 | 100.1 |
| **Total operating revenues** | **4,721.5** | 3,823.0 | 3,683.7 |
| **Operating expenses** | | | |
| Operations and maintenance | **2,195.8** | 2,152.4 | 2,065.6 |
| Purchased power | **358.7** | 248.2 | 123.7 |
| Depreciation, amortization and accretion | **841.0** | 826.7 | 818.8 |
| **Total operating expenses** | **3,395.5** | 3,227.3 | 3,008.1 |
| **Net operating revenues** | **1,326.0** | 595.7 | 675.6 |
| **Interest expense and other income, net** | | | |
| Interest expense | **417.7** | 427.3 | 467.9 |
| Allowance for funds used during construction | **(24.9)** | (25.9) | (27.7) |
| Interest income | **(10.6)** | (1.5) | (3.3) |
| Other income, net | **(20.3)** | (202.0) | (7.0) |
| **Total interest expense and other income, net** | **361.9** | 197.9 | 429.9 |
| **Net revenues** | **964.1** | 397.8 | 245.7 |
| Accumulated net revenues, beginning of year | **4,912.6** | 4,537.0 | 4,315.4 |
| Irrigation assistance | **(17.1)** | (22.2) | (24.1) |
| **Accumulated net revenues, end of year** | **$ 5,859.6** | $ 4,912.6 | $ 4,537.0 |

***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)

| | | 2022 | | 2021 | | 2020 |
|---|---|---|---|---|---|---|
| **Cash flows from operating activities** | | | | | | |
| Net revenues | **$** | **964.1** | $ | 397.8 | $ | 245.7 |
| Adjustments to reconcile net revenues to cash provided by operations: | | | | | | |
| Depreciation, amortization and accretion | | **841.0** | | 826.7 | | 818.8 |
| Deferred payments for Energy Northwest-related O&M and interest | | **-** | | - | | 10.0 |
| Other | | **(13.4)** | | (8.2) | | 6.8 |
| Changes in: | | | | | | |
| Receivables and unbilled revenues | | **(180.3)** | | 30.0 | | (15.2) |
| Materials and supplies | | **0.1** | | (2.4) | | (0.6) |
| Prepaid expenses | | **(9.5)** | | (3.1) | | (5.4) |
| Accounts payable and other | | **334.1** | | 465.6 | | 115.0 |
| Regulatory assets and liabilities | | **(7.4)** | | (291.2) | | (25.9) |
| IOU exchange benefits | | **(208.2)** | | (188.2) | | (182.4) |
| Nonfederal nuclear decommissioning trusts | | **105.3** | | (105.5) | | (9.7) |
| Other assets and liabilities | | **(49.0)** | | 25.9 | | 15.2 |
| **Net cash provided by operating activities** | | **1,776.8** | | 1,147.4 | | 972.3 |
| **Cash flows from investing activities** | | | | | | |
| Investment in utility plant, including AFUDC | | **(693.8)** | | (623.8) | | (587.6) |
| Proceeds from sale of utility plant | | **13.2** | | 2.0 | | 8.6 |
| U.S. Treasury securities: | | | | | | |
| Purchases | | **(1,250.0)** | | - | | - |
| Maturities | | **750.0** | | - | | - |
| Deposits to nonfederal nuclear decommissioning trusts | | **(4.7)** | | (4.3) | | (4.1) |
| Lease-purchase trust funds: | | | | | | |
| Deposits to | | **-** | | (19.6) | | (71.0) |
| Receipts from | | **-** | | 27.1 | | 110.2 |
| **Net cash used for investing activities** | | **(1,185.3)** | | (618.6) | | (543.9) |
| **Cash flows from financing activities** | | | | | | |
| Federal appropriations: | | | | | | |
| Proceeds | | **43.1** | | 119.4 | | 24.1 |
| Repayment | | **(5.0)** | | (49.1) | | (75.3) |
| Borrowings from U.S. Treasury: | | | | | | |
| Proceeds | | **744.0** | | 741.0 | | 1,757.0 |
| Repayment | | **(694.2)** | | (760.7) | | (1,388.0) |
| Nonfederal debt: | | | | | | |
| Proceeds | | **-** | | 6.6 | | 71.2 |
| Repayment | | **(208.5)** | | (225.9) | | (470.0) |
| Debt extinguishment costs | | **-** | | (1.5) | | (5.1) |
| Customers: | | | | | | |
| Net advances for construction | | **20.3** | | 42.3 | | 20.2 |
| Repayment of funds used for construction | | **(21.0)** | | (17.5) | | (15.8) |
| Irrigation assistance | | **(17.1)** | | (22.2) | | (24.1) |
| **Net cash used for financing activities** | | **(138.4)** | | (167.6) | | (105.8) |
| **Net increase in cash, cash equivalents and restricted cash** | | **453.1** | | 361.2 | | 322.6 |
| Cash, cash equivalents and restricted cash at beginning of year | | **1,218.7** | | 857.5 | | 534.9 |
| **Cash, cash equivalents and restricted cash at end of year** | **$** | **1,671.8** | $ | 1,218.7 | $ | 857.5 |
| Less: Restricted cash at end of year, reported in Deferred charges and other | | **8.8** | | 10.8 | | 11.0 |
| **Cash and cash equivalents at end of year** | **$** | **1,663.0** | $ | 1,207.9 | $ | 846.5 |
| **Supplemental disclosures:** | | | | | | |
| Cash paid for interest, net of amount capitalized | **$** | **396.4** | $ | 384.4 | $ | 440.2 |
| Significant noncash investing and financing activities: | | | | | | |
| Nonfederal debt increase | **$** | **705.6** | $ | 1,577.0 | $ | 916.2 |
| Nonfederal debt decrease | **$** | **(507.4)** | $ | (1,288.2) | $ | (785.8) |
| Nonfederal debt cost of issuance | **$** | **(3.0)** | $ | (6.6) | $ | (4.6) |
| 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 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 and Reclamation 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 will conclude on Sept. 30, 2023.

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 in connection with a periodic increase to the Columbia Generating Station (CGS) 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.

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 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, 2022, and 2021, 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, 2022, and 2021, 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. Investments in U.S. Treasury securities as of Sept. 30, 2022, had original maturities of between 91 days and one year. (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 2022, 2021 and 2020, 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. For the allowance as of Sept. 30, 2022, and 2021, management considered the effects of the COVID-19 pandemic. The allowance is not material to the financial statements.

## Derivative instruments

Derivative instruments are measured at fair value and recognized on the Combined Balance Sheets as either Deferred charges and other or as Deferred credits and other, except for certain contracts eligible for the normal purchases and normal sales exception under derivatives and hedging accounting guidance. Derivative instruments reported by the FCRPS consist primarily of forward electricity contracts, which can be considered normal purchases and normal sales if they 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. 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. 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 income, net

Other income, net primarily includes dividend income and realized gains and losses associated with the nonfederal nuclear decommissioning trusts for CGS. In addition, losses incurred because of early debt extinguishment are recorded to this caption. In fiscal year 2021, Other income, 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 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. The cost of this program is collected through 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 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, 2022, which is the date the financial statements were issued.

# 2. Revenue Recognition

## DISAGGREGATED REVENUE

| *Years ended Sept. 30 - millions of dollars* | 2022 | 2021 | 2020 |
|---|---|---|---|
| Sales | | | |
| Power | | | |
| Firm | $ 2,095.0 | $ 2,122.7 | $ 2,113.7 |
| Surplus[1] | 1,337.0 | 561.2 | 445.7 |
| Transmission | 1,070.4 | 966.1 | 938.3 |
| Other[2] | 102.2 | 77.8 | 85.9 |
| Sales | $ 4,604.6 | $ 3,727.8 | $ 3,583.6 |
| U.S. Treasury credits[3] | 116.9 | 95.2 | 100.1 |
| Total operating revenues[4] | $ 4,721.5 | $ 3,823.0 | $ 3,683.7 |

[1] Surplus revenue includes $575.2 million, $226.4 million, and $198.5 million of derivative commodity contracts and related operational hedging activity for fiscal years 2022, 2021 and 2020, respectively, which are not considered revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
[2] Other revenue includes $41.7 million, $22.7 million and $24.1 million for fiscal years 2022, 2021 and 2020, 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 $3,987.7 million, $3,478.7 million and $3,361.0 million for fiscal years 2022, 2021 and 2020, 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 2022, 2021 and 2020 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. BPA applies the credits toward its annual payment to the U.S. Treasury, which is made to pay federal debt, interest and other federal obligations. 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* | 2022 | 2021 |
|---|---|---|
| Receivable assets | | |
| Accounts receivable, net of allowance | $ 41.7 | $ 18.3 |
| Accrued unbilled revenues | 458.2 | 301.3 |
| Contract liabilities | | |
| Customer prepaid power purchases | $ 163.0 | $ 185.7 |
| Third AC Intertie capacity agreements | 86.1 | 87.5 |
| Unearned revenue from customer deposits | 37.8 | 18.5 |
| Revenue recognized during the fiscal year from amounts included in contract liabilities at the beginning of the year | $ 105.4 | $ 77.2 |

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* | 2022 | 2021 | 2022 Estimated average service lives |
|---|---|---|---|
| **Completed plant** | | | |
| Federal system hydro generation assets | $ 10,171.3 | $ 9,958.9 | 75 years |
| Transmission assets | 11,023.7 | 10,690.5 | 51 years |
| Other assets | 105.0 | 109.4 | 8 years |
| Completed plant | $ 21,300.0 | $ 20,758.8 | |
| **Accumulated depreciation** | | | |
| Federal system hydro generation assets | $ (4,002.2) | $ (3,874.6) | |
| Transmission assets | (3,939.0) | (3,827.5) | |
| Other assets | (53.6) | (56.5) | |
| Accumulated depreciation | $ (7,994.8) | $ (7,758.6) | |
| **Construction work in progress** | | | |
| Federal system hydro generation assets | $ 532.7 | $ 570.6 | |
| Transmission assets | 754.5 | 738.6 | |
| Other assets | 29.5 | 33.6 | |
| Construction work in progress | $ 1,316.7 | $ 1,342.8 | |
| **Nonfederal generation** | $ 3,404.6 | $ 3,527.7 | |
| Net utility plant and nonfederal generation | $ 18,026.5 | $ 17,870.7 | |

**Allowance for funds used during construction**

| *Fiscal year* | 2022 | 2021 | 2020 |
|---|---|---|---|
| BPA rate | 2.4% | 2.6% | 3.0% |
| Appropriated rate | 0.1% | 0.1% | 1.8% |

Amounts accrued in Accounts payable and other on the Combined Balance Sheets for Construction work in progress assets were approximately $93 million, $92 million, and $77 million as of September 30, 2022, 2021, and 2020, 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 1 to 37 years. Finance leases are primarily for transmission lines and equipment. Finance lease terms range from 1 to 65 years. There were no material lessor arrangements as of Sept. 30, 2022, and 2021.

The following table provides supplemental balance sheet information related to leases:

| *As of Sept. 30 — millions of dollars* | Financial Statement Line Item | 2022 | 2021 |
|---|---|---|---|
| Operating leases | | | |
| ROU assets | Deferred charges and other | $ 98.3 | $ 111.2 |
| Short-term lease liability | Accounts payable and other | 31.6 | 16.3 |
| Long-term lease liability | Deferred credits and other | 66.7 | 94.9 |
| Finance leases | | | |
| ROU assets | Completed plant | 95.8 | 93.3 |
| Short-term lease liability | Nonfederal debt | 7.3 | 3.1 |
| Long-term lease liability | Nonfederal debt | 93.8 | 94.8 |

The following table provides supplemental expense information related to total lease costs:

| *Years ended Sept. 30 — millions of dollars* | Financial Statement Line Item | 2022 | 2021 | 2020 |
|---|---|---|---|---|
| Operating lease cost[1] | Operations and maintenance | $ 18.6 | $ 19.0 | $ 15.9 |
| Finance lease cost: | | | | |
| Amortization of ROU assets | Depreciation, amortization and accretion | 4.5 | 3.7 | 2.3 |
| Interest on lease liabilities | Interest expense | 5.1 | 5.0 | 4.1 |
| Total lease costs | | $ 28.2 | $ 27.7 | $ 22.3 |

[1]Includes variable lease costs, which were immaterial for the fiscal years ended Sept. 30, 2022, 2021 and 2020.

| | Weighted-average remaining lease term | Weighted-average discount rate |
|---|---|---|
| Operating leases | 7.6 years | 2.6% |
| Finance leases | 49.7 years | 5.0% |

The following provides supplemental cash flow information related to leases:

| *Years ended Sept. 30 - millions of dollars* | 2022 | 2021 | 2020 |
|---|---|---|---|
| Cash paid for amounts included in the measurement of lease liabilities | | | |
| Operating cash outflows: | | | |
| Operating lease payments | $ 18.6 | $ 19.0 | $ 15.9 |
| Interest on finance leases | 5.1 | 5.0 | 4.1 |
| Financing cash outflows: | | | |
| Principal payments on finance lease | 3.8 | 2.9 | 1.7 |
| Right-of-use assets obtained in exchange for new lease obligations | | | |
| Operating leases | 3.0 | 13.4 | 115.2 |
| Finance leases | 7.0 | 11.9 | 74.1 |

The following tables provide maturities of operating lease liabilities:

| *As of Sept. 30 - millions of dollars* | 2022 |
|---|---|
| 2023 | $ 18.0 |
| 2024 | 17.0 |
| 2025 | 14.4 |
| 2026 | 11.2 |
| 2027 | 11.1 |
| 2028 and thereafter | 37.3 |
| Total undiscounted lease liabilities | $ 109.0 |
| Less: Amounts representing interest | 10.7 |
| Total lease liabilities | $ 98.3 |

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 | 2022 | 2021 |
|---|---|---|
| IOU exchange benefits | $ 1,514.0 | $ 1,722.2 |
| Terminated nuclear facilities | 1,495.8 | 1,566.2 |
| Columbia River Fish Mitigation | 766.1 | 786.2 |
| Fish and wildlife measures | 233.9 | 253.9 |
| Decommissioning and site restoration | 124.8 | 3.8 |
| Conservation measures | 81.3 | 123.3 |
| Trojan decommissioning and site restoration | 77.3 | 76.7 |
| Terminated I-5 Corridor Reinforcement Project | 52.0 | 78.0 |
| Spacer damper replacement program | 46.8 | 48.6 |
| Legal claims and settlements | 22.0 | 22.0 |
| Federal Employees' Compensation Act | 18.9 | 22.3 |
| Derivative instruments | 11.0 | 67.6 |
| Terminated hydro facilities | 4.2 | 6.1 |
| Other | 4.1 | 4.6 |
| Total | $ 4,452.2 | $ 4,781.5 |

"**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.)

"**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.

"**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.

"**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.

"**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.

"**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.)

**"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.

"**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.

"**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 7, Deferred Charges and Other.)

"**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.)

"**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.)

Regulatory liabilities include the following items:

## REGULATORY LIABILITIES

| *As of Sept. 30 — millions of dollars* | 2022 | 2021 |
|---|---|---|
| Capitalization adjustment | $ 887.8 | $ 952.7 |
| Accumulated plant removal costs | 621.0 | 572.5 |
| Derivative instruments | 55.4 | 25.2 |
| Other | 1.4 | 2.2 |
| Total | $ 1,565.6 | $ 1,552.6 |

"**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 2022, 2021 and 2020.

"**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* | 2022 | 2021 |
|---|---|---|
| CGS decommissioning and site restoration | $ 884.3 | $ 848.2 |
| Trojan decommissioning | 77.3 | 76.7 |
| Energy Northwest Projects 1 and 4 site restoration | 2.7 | 4.3 |
| Total | $ 964.3 | $ 929.2 |

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* | 2022 | 2021 | 2020 |
|---|---|---|---|
| Beginning Balance | $ 929.2 | $ 890.7 | $ 821.2 |
| Activities: | | | |
| Accretion | 38.6 | 37.1 | 34.9 |
| Expenditures | (6.1) | (8.2) | (3.0) |
| Revisions | 2.6 | 9.6 | 37.6 |
| Ending Balance | $ 964.3 | $ 929.2 | $ 890.7 |

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 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.

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 $1.5 million, $1.6 million, and $1.3 million in fiscal years 2022, 2021, and 2020, 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* | 2022 | | 2021 | |
|---|---|---|---|---|
| | Amortized cost | Fair value | Amortized cost | Fair value |
| Equity securities | $ 439.4 | $ 337.8 | $ 423.3 | $ 417.4 |
| Debt securities | 82.5 | 59.3 | 76.1 | 77.5 |
| Cash and cash equivalents | 17.5 | 17.5 | 20.3 | 20.3 |
| Total | $ 539.4 | $ 414.6 | $ 519.7 | $ 515.2 |

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, 2022, and 2021 were $397.1 million and $494.9 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 $17.5 million and $20.3 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 income, net in the Combined Statements of Revenues and Expenses and were considered when establishing rates for fiscal years 2020 through 2022. Realized gains reported for fiscal years 2022, 2021 and 2020 were $2.9 million, $164.1 million, and $4.2 million, respectively.

Contribution payments to the CGS trust fund accounts for fiscal years 2022, 2021 and 2020 were $4.7 million, $4.3 million and $4.1 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* | 2022 | 2021 |
|---|---|---|
| Operating leases | $ 98.3 | $ 111.2 |
| Derivative instruments | 55.4 | 25.2 |
| Lease-Purchase trust funds | 34.0 | 35.1 |
| Funding agreements | 28.3 | 24.6 |
| Spectrum Relocation Fund | 8.8 | 10.8 |
| Cloud computing arrangements | 7.8 | 0.8 |
| Other | 4.6 | 6.9 |
| Total | $ 237.2 | $ 214.6 |

“**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 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 $19.2 million and $19.3 million as of Sept. 30, 2022 and 2021, and are recorded at amortized cost. The fair value of held-to-maturity investments exceeded amortized cost by approximately $2 million and $7 million as of Sept. 30, 2022 and 2021, respectively. Unrealized gains comprise the difference between amortized cost and fair value for both years. Held-to-maturity investments as of Sept. 30, 2022, mature in November 2030.

As of Sept. 30, 2022, and 2021, trust balances also included cash and cash equivalents of $14.7 million and $15.8 million, respectively.

Investments classified as available-for-sale were $0.1 million and $0  at Sept. 30, 2022, and 2021, 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 2022, 2021, and 2020. Available-for-sale investments as of Sept. 30, 2022, mature in December 2022. (See Note 13, Fair Value Measurements.)

“**Funding agreements**” represent deferred costs associated with BPA’s contractual obligations to determine the feasibility of certain joint transmission projects.

“**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.

# 8. Debt and Appropriations

| *As of Sept. 30 — millions of dollars* | | 2022 | | 2021 | |
|---|---|---|---|---|---|
| | 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 | $ 3,295.9 | 4.5% | $ 3,246.7 | 4.5% |
| Cowlitz Falls Hydro Project | 4.0 – 5.3% through 2032 | 56.4 | 5.5 | 60.6 | 5.4 |
| Terminated nonfederal generation: | | | | | |
| Nuclear Project 1 | 0.9 – 5.0% through 2042 | 824.1 | 4.7 | 809.0 | 4.8 |
| Nuclear Project 3 | 2.9 – 5.0% through 2042 | 950.3 | 4.9 | 929.6 | 4.9 |
| Northern Wasco Hydro Project | 5.0% through 2024 | 5.3 | 5.0 | 6.9 | 5.0 |
| Lease-Purchase Program: | | | | | |
| Lease-purchase liability | 1.9 – 3.7% through 2046 | 1,838.3 | 2.8 | 1,910.3 | 2.8 |
| NIFC debt | 5.4% through 2034 | 119.0 | 5.4 | 119.0 | 5.4 |
| Finance lease liability | 0.5 – 6.9% through 2087 | 101.1 | 5.0 | 97.9 | 5.2 |
| Other financial liability | 3.4% through 2043 | 16.5 | 3.4 | 17.5 | 3.5 |
| Customer prepaid power purchases | 4.3 – 4.6% through 2028 | 163.0 | 4.5 | 185.7 | 4.5 |
| **Total Nonfederal debt** | | $ 7,369.9 | 4.2% | $ 7,383.2 | 4.2% |
| **Federal debt and appropriations** | | | | | |
| Borrowings from U.S. Treasury | 0.2 – 5.9% through 2052 | $ 5,678.7 | 3.0% | $ 5,628.9 | 2.6% |
| Federal appropriations | 1.4 – 4.5% through 2072 | 1,242.9 | 3.3 | 1,233.3 | 3.3 |
| Federal appropriations (not scheduled for repayment) | | 398.0 | n/a | 369.5 | n/a |
| **Total Federal debt and appropriations** | | $ 7,319.6 | 3.1% | $ 7,231.7 | 2.7% |
| **Total debt and appropriations** | | $ 14,689.5 | 3.6% | $ 14,614.9 | 3.5% |

## 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, in October 2023 at 100% of the principal amount.

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 $287.4 million,

$319.4 million and $267.6 million in fiscal years 2022, 2021 and 2020, 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 2022 and 2021, BPA recorded gains of $2.2 million and $2.7 million when certain Energy Northwest debt was extinguished via the issuance of long-term debt. BPA recorded no such gains during fiscal year 2020.

Energy Northwest debt of $2.86 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 2032 at 100% of the principal amount.

As of Sept. 30, 2022, and 2021, Energy Northwest could borrow $110 million under a line-of-credit borrowing arrangement with a banking institution. As of Sept. 30, 2022, and 2021, 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. (See Note 9, Variable Interest Entities.) During fiscal year 2021, BPA recorded a $1.5 million loss when certain lease-purchase liabilities were extinguished via the issuance of long-term debt. BPA recorded no such transaction during fiscal year 2022.

Under the Lease-Purchase Program, BPA consolidates one special purpose corporation (Northwest Infrastructure Financing Corporation or NIFC). As of Sept. 30, 2022, and 2021, 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

These agreements are with transmission customers. BPA is deemed the accounting owner of the assets, which are included in Utility plant on the Combined Balance Sheets. The agreements contain provisions that allow BPA to purchase the related assets at any time during each contract term, with ownership transferring to BPA at the end of each 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, 2022, and 2021, no bonds outstanding were related to Northwest Power Act expenses.

As of Sept. 30, 2022, $626.1 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 $5.05 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, 2021, $531.3 million of variable-rate bonds were outstanding.

### 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.

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 2022 and 2021. 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.

| 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 |
|---|---|---|---|---|---|
| 2023 | $ 520.4 | $ 8.5 | $ 294.0 | $ - | $ 822.9 |
| 2024 | 557.9 | 7.2 | 199.0 | - | 764.1 |
| 2025 | 654.0 | 7.1 | 178.0 | - | 839.1 |
| 2026 | 580.2 | 7.0 | 211.0 | - | 798.2 |
| 2027 | 527.5 | 7.0 | 183.0 | - | 717.5 |
| 2028 and thereafter | 4,974.2 | 175.3 | 4,613.7 | 1,640.9 | 11,404.1 |
| Total | $ 7,814.2 | $ 212.1 | $ 5,678.7 | $ 1,640.9 | $ 15,345.9 |
| Less: Executory costs | 2.7 | - | - | - | 2.7 |
| Less: Amount representing interest | 773.7 | 111.0 | - | - | 884.7 |
| Less: Unamortized debt issuance cost | 13.6 | - | - | - | 13.6 |
| Plus: Unamortized premiums | 244.6 | - | - | - | 244.6 |
| Present value of debt | 7,268.8 | 101.1 | 5,678.7 | 1,640.9 | 14,689.5 |
| Less: Current portion | 461.2 | 7.3 | 294.0 | - | 762.5 |
| Long-term debt | $ 6,807.6 | $ 93.8 | $ 5,384.7 | $ 1,640.9 | $ 13,927.0 |

## 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 $20.5 million and Nonfederal debt of $119 million as of both Sept. 30, 2022, and 2021. 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 $16.5 million, $20.6 million and $23.2 million in fiscal years 2022, 2021 and 2020, 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* | | |
|---|---|---|
| 2023 | $ | 259.0 |
| 2024 | | 273.6 |
| 2025 | | 273.6 |
| 2026 | | 286.1 |
| 2027 | | 286.1 |
| 2028 | | 286.1 |
| Subtotal of annual payments | | 1,664.5 |
| Less: Discount for present value | | 150.5 |
| IOU exchange benefits | $ | 1,514.0 |

## 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, 2022, totaling $1.66 billion. Amounts recorded of $1.51 billion at Sept. 30, 2022, 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* | 2022 | 2021 |
|---|---|---|
| Interconnection agreements | $ 203.8 | $ 188.7 |
| Deferred project revenue funded in advance | 141.5 | 144.5 |
| Third AC Intertie capacity agreements | 86.1 | 87.5 |
| Operating leases | 66.7 | 94.9 |
| Service deposits | 58.1 | 24.0 |
| Unearned revenue from customer deposits | 37.8 | 18.5 |
| Federal Employees' Compensation Act | 18.9 | 22.3 |
| Derivative instruments | 11.0 | 67.6 |
| Fiber optic leasing fees | 6.4 | 7.0 |
| Other | 3.9 | 3.3 |
| Total | $ 634.2 | $ 658.3 |

"**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.

**"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.)

"**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.

"**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.)

"**Federal Employees' Compensation Act**" reflects the actuarial estimated amount of future payments for current recipients of BPA's worker compensation benefits.

"**Derivative instruments**" reflect the unrealized loss of the derivative portfolio, which primarily includes physical power purchase and sale transactions.

"**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.)

# 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 2022, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2022, BPA had $208.2 million in credit exposure related to purchase and sale contracts after taking into account netting rights. Of this $208.2 million, $196.7 million was related to investment grade counterparties and $11.5 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 records unrealized gains and losses in 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 as 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, 2022, the derivative commodity contracts recorded at fair value totaled 3.0 million megawatt hours (MWh), gross basis, with delivery months extending to September 2023.

As of Oct. 1, 2021, BPA shifted from reporting gross fair value amounts of derivative instruments subject to a master netting arrangement, to reporting net fair value amounts of derivative instrument subject to a master netting arrangement (excluding contracts designated as normal purchases or normal sales), in accordance with ASC 210 and 815. Due to the immateriality of the difference between the two allowable reporting methods, BPA adopted the policy change prospectively, and did not adjust prior period comparative derivative amounts. (See Note 7, Deferred Charges and Other and Note 11, Deferred Credits and Other.) 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 for fiscal year 2022, BPA's derivative position would have resulted in assets of $56.5 million and liabilities of $12.1 million as of Sept. 30, 2022. If reported net for fiscal year 2021, BPA's derivative position would have resulted in assets of $22.9 million and liabilities of $65.3 million as of Sept. 30, 2021. (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, 2022, and 2021. There were no transfers between Level 2 and Level 3 during fiscal years 2022 and 2021.

## ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

*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) |

*As of Sept. 30, 2021 — millions of dollars*

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Assets | | | | |
| Nonfederal nuclear decommissioning trusts | | | | |
| Equity securities | $ 417.4 | $ — | $ — | $ 417.4 |
| Debt securities | 77.5 | — | — | 77.5 |
| Cash and cash equivalents | 20.3 | — | — | 20.3 |
| Derivative instruments [1] | | | | |
| Commodity contracts | 0.1 | 24.1 | 1.0 | 25.2 |
| Total | $ 515.3 | $ 24.1 | $ 1.0 | $ 540.4 |
| Liabilities | | | | |
| Derivative instruments [1] | | | | |
| Commodity contracts | $ (26.9) | $ (24.5) | $ (16.2) | $ (67.6) |
| Total | $ (26.9) | $ (24.5) | $ (16.2) | $ (67.6) |

[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.

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 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, 2022* | | | | | | | |
| Physical forward power contracts | $ 13.5 | $ (1.0) | Discounted cash flow | Electricity forward price | $ 36.2 | $ 180.3 | $ 112.0 |
| *As of Sept. 30, 2021* | | | | | | | |
| Physical forward power contracts | $ 1.0 | $ (16.2) | Discounted cash flow | Electricity forward price | $ 28.0 | $ 126.4 | $ 83.1 |

[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.

## COMMODITY CONTRACTS

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* | 2022 | 2021 |
|---|---|---|
| Beginning Balance | $ (15.2) | $ 5.5 |
| Changes in unrealized gains (losses)[1] | 27.7 | (20.7) |
| Ending Balance | $ 12.5 | $ (15.2) |

[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 | 2022 | | 2021 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| **Nonfederal Debt** | | | | |
| **Nonfederal generation:** | | | | |
| Columbia Generating Station | $ 3,295.9 | $ 3,182.8 | $ 3,246.7 | $ 3,585.9 |
| Cowlitz Falls Project | 56.4 | 61.6 | 60.6 | 70.1 |
| **Terminated nonfederal generation:** | | | | |
| Nuclear Project 1 | 824.1 | 832.7 | 809.0 | 908.5 |
| Nuclear Project 3 | 950.3 | 995.0 | 929.6 | 1,101.4 |
| Northern Wasco Hydro Project | 5.3 | 5.4 | 6.9 | 7.5 |
| **Lease-Purchase Program:** | | | | |
| Lease-purchase liability | 1,838.3 | 1,475.3 | 1,910.3 | 1,980.0 |
| NIFC debt | 119.0 | 125.6 | 119.0 | 160.1 |
| **Other financial liability** | 16.5 | 9.0 | 17.5 | 15.1 |
| **Customer prepaid power purchases** | 163.0 | 163.0 | 185.7 | 185.7 |
| **Federal debt** | | | | |
| Borrowings from U.S. Treasury | $ 5,678.7 | $ 4,907.9 | $ 5,628.9 | $ 6,126.7 |

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, 2022, and 2021.

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, 2022, and 2021.

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, 2022, BPA has long-term fish and wildlife agreements with estimated contractual commitments of $372.9 million, which are likely to result in future expenses or regulatory assets. These agreements will expire at various dates through fiscal year 2027 and do not include the Columbia Basin Fish Accords extension agreements, which are described below.

As of Nov. 1, 2022, BPA and its federal partners USACE and Reclamation are in the process of signing extension agreements with current Accords partners, namely certain states and tribes, to extend the Columbia Basin Fish Accords. 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 existing agreements expired Sept. 30, 2022, and will be extended until Sept. 30, 2025. The extension agreements are expected to 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* | | |
|---|---|---|
| 2023 | $ | 13.4 |
| 2024 | | 8.2 |
| 2025 | | 13.1 |
| 2026 | | 20.5 |
| 2027 | | 6.3 |
| 2028 through 2045 | | 185.8 |
| Total | $ | 247.3 |

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 $247.3 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* | | |
|---|---|---|
| 2023 | $ | 43.6 |
| 2024 | | 40.0 |
| 2025 | | 35.4 |
| 2026 | | 30.9 |
| Total | $ | 149.9 |

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 $7.6 million, $83.7 million and $43.8 million for fiscal years 2022, 2021 and 2020, 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.

## NUCLEAR INSURANCE

BPA is a member of the 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 $18.4 million. For the Excess Property, Excess Decontamination Liability and Decommissioning Liability Insurance policy, the maximum assessment is $6.4 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $5.1 million.

Additionally, in the event of a nuclear accident resulting in public liability losses exceeding $450.0 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 $137.6 million limited to $20.5 million per incident within one calendar year. Assessments would be included in BPA's costs and recovered through rates. As of Sept. 30, 2022, 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, 2022, 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

Based upon fiscal year 2022 financial results and year-end reserves for risk levels for both power and transmission, a reserves distribution clause (RDC) is expected to trigger for application to fiscal year 2023 power and transmission rates. The RDC is a rate adjustment mechanism that triggers if reserves for risk levels exceed certain cash on hand targets at September 30 for each business line. Terms of the RDC are discussed in the BP-22 rate case, which states 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. Final determination of the amounts and use of the Power and Transmission RDC will occur by December 15, 2022, with application of most RDC actions likely to occur between December and September of fiscal year 2023. As of Sept. 30, 2022, no liability has been incurred 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, 2022, no material liability has been recorded for the above legal matters.

# Federal Columbia River Power System
## Combined Balance Sheets (Unaudited)
(Millions of Dollars)

| | As of December 31, 2022 | As of September 30, 2022 |
|---|---|---|
| **Assets** | | |
| **Utility plant and nonfederal generation** | | |
| Completed plant | $ **21,379.2** | $ 21,300.0 |
| Accumulated depreciation | **(8,077.0)** | (7,994.8) |
| Net completed plant | **13,302.2** | 13,305.2 |
| Construction work in progress | **1,389.1** | 1,316.7 |
| **Net utility plant** | **14,691.3** | 14,621.9 |
| Nonfederal generation | **3,388.7** | 3,404.6 |
| **Net utility plant and nonfederal generation** | **18,080.0** | 18,026.5 |
| **Current assets** | | |
| Cash and cash equivalents | **1,465.6** | 1,663.0 |
| Short-term investments in U.S. Treasury securities | **756.0** | 500.8 |
| Accounts receivable, net of allowance | **43.2** | 41.7 |
| Accrued unbilled revenues | **412.9** | 458.2 |
| Materials and supplies, at average cost | **114.1** | 109.4 |
| Prepaid expenses | **64.1** | 49.0 |
| **Total current assets** | **2,855.9** | 2,822.1 |
| **Other assets** | | |
| Regulatory assets | **4,376.0** | 4,452.2 |
| Nonfederal nuclear decommissioning trusts | **454.0** | 414.6 |
| Deferred charges and other | **237.8** | 237.2 |
| **Total other assets** | **5,067.8** | 5,104.0 |
| **Total assets** | $ **26,003.7** | $ 25,952.6 |

*This BPA-approved financial information was made publicly available on 1-27-2023.*

# Federal Columbia River Power System

## Combined Balance Sheets (Unaudited)

(Millions of Dollars)

| | As of December 31, 2022 | As of September 30, 2022 |
|---|---|---|
| **Capitalization and Liabilities** | | |
| **Capitalization and long-term liabilities** | | |
| Accumulated net revenues | **$ 5,723.5** | $ 5,859.6 |
| Debt | | |
| Federal appropriations | **1,644.7** | 1,640.9 |
| Borrowings from U.S. Treasury | **5,278.5** | 5,384.7 |
| Nonfederal debt | **6,892.1** | 6,901.4 |
| **Total capitalization and long-term liabilities** | **19,538.8** | 19,786.6 |
| **Commitments and contingencies (See Note 14 to 2022 Audited Financial Statements)** | | |
| **Current liabilities** | | |
| Debt | | |
| Borrowings from U.S. Treasury | **380.2** | 294.0 |
| Nonfederal debt | **512.7** | 468.5 |
| Accounts payable and other | **862.8** | 725.4 |
| **Total current liabilities** | **1,755.7** | 1,487.9 |
| **Other liabilities** | | |
| Regulatory liabilities | **1,553.8** | 1,565.6 |
| IOU exchange benefits | **1,460.8** | 1,514.0 |
| Asset retirement obligations | **974.1** | 964.3 |
| Deferred credits and other | **720.5** | 634.2 |
| **Total other liabilities** | **4,709.2** | 4,678.1 |
| **Total capitalization and liabilities** | **$ 26,003.7** | $ 25,952.6 |

*This BPA-approved financial information was made publicly available on 1-27-2023.*

# Federal Columbia River Power System

## Combined Statements of Revenues and Expenses (Unaudited)

(Millions of Dollars)

| | Three Months Ended December 31, | | Fiscal Year-to-Date Ended December 31, | |
|---|---|---|---|---|
| | **2022** | 2021 | **2022** | 2021 |
| **Operating revenues** | | | | |
| Sales | **$ 1,006.8** | $ 966.9 | **$ 1,006.8** | $ 966.9 |
| U.S. Treasury credits | **55.9** | 36.6 | **55.9** | 36.6 |
| **Total operating revenues** | **1,062.7** | 1,003.5 | **1,062.7** | 1,003.5 |
| **Operating expenses** | | | | |
| Operations and maintenance | **547.5** | 509.3 | **547.5** | 509.3 |
| Purchased power | **360.2** | 69.1 | **360.2** | 69.1 |
| Depreciation, amortization and accretion | **210.9** | 209.9 | **210.9** | 209.9 |
| **Total operating expenses** | **1,118.6** | 788.3 | **1,118.6** | 788.3 |
| **Net operating revenues (expenses)** | **(55.9)** | 215.2 | **(55.9)** | 215.2 |
| **Interest expense and other income, net** | | | | |
| Interest expense | **111.6** | 105.8 | **111.6** | 105.8 |
| Allowance for funds used during construction | **(10.0)** | (6.8) | **(10.0)** | (6.8) |
| Interest income | **(15.3)** | (0.3) | **(15.3)** | (0.3) |
| Other income, net | **(6.1)** | (9.9) | **(6.1)** | (9.9) |
| **Total interest expense and other income, net** | **80.2** | 88.8 | **80.2** | 88.8 |
| **Net revenues (expenses)** | **$ (136.1)** | $ 126.4 | **$ (136.1)** | $ 126.4 |

*This BPA-approved financial information was made publicly available on 1-27-2023.*

# Independent Auditors' Report

To the Board of Directors of
Energy Northwest

**Report on the Audit of the Financial Statements**

***Opinions***

We have audited the financial statements of the business-type activities of Energy Northwest, as of and for the year ended June 30, 2022, and the related notes to the financial statements, which collectively comprise Energy Northwest's basic financial statements as listed in the table of contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the business-type activities of Energy Northwest as of June 30, 2022, and the changes in financial position and cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

***Basis for Opinions***

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS) and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States (GAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of Energy Northwest 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 opinions.

***Emphasis of Matter***

As discussed in Note 1, Energy Northwest adopted the provisions of GASB Statement No. 87, *Leases*, effective July 1, 2021. Our opinions are not modified with respect to this matter.

***Responsibilities of Management for the Financial Statements***

Management is responsible for the preparation and fair presentation of the 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 financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Energy Northwest's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

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### *Auditors' Responsibilities for the Audit of the Financial Statements*

Our objectives are to obtain reasonable assurance about whether the 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 opinions. 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 GAAS and GAS will 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 financial statements.

In performing an audit in accordance with GAAS and GAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the 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 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 Energy Northwest'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 financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Energy Northwest'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.

### *Required Supplementary Information*

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

## Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated September 29, 2022 on our consideration of Energy Northwest's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of Energy Northwest's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering Energy Northwest's internal control over financial reporting and compliance.

Baker Tilly US, LLP

Madison, Wisconsin
September 29, 2022

## Energy Northwest Management's Discussion and Analysis (Unaudited)

Energy Northwest is a municipal corporation and joint operating agency of the state of Washington. Each Energy Northwest business unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by business unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the fiscal year (FY) ended June 30, 2022, with the basic financial statements for the FY ended June 30, 2021.

Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest's records are maintained as prescribed by the Governmental Accounting Standards Board (GASB). (See Note 1 to the Financial Statements.)

Because each business unit is financed and accounted for separately, the following section on financial performance is discussed by business unit to aid in analysis of assessing the financial position of each individual business unit. For comparative purposes only, the table on the following page represents a memorandum only total for Energy Northwest, as a whole, for FY 2022 and FY 2021.

The Financial Statements for Energy Northwest include the Statements of Net Position; Statements of Revenues, Expenses, and Changes in Net Position; and Statements of Cash Flows for each of the business units, and Notes to Financial Statements.

The Statements of Net Position present the financial position of each business unit on an accrual basis. The Statements of Net Position report financial information about construction work in progress, the amount of resources and obligations, restricted accounts, and due to/from balances for each business unit. (See Note 1 to the Financial Statements.)

The Statements of Revenues, Expenses, and Changes in Net Position provide financial information relating to all expenses, revenues and equity that reflect the results of each business unit and its related activities over the course of the fiscal year. The financial information provided aids in benchmarking activities, conducting comparisons to evaluate progress, and determining whether the business unit has successfully recovered its costs.

The Statements of Cash Flows reflect cash receipts and disbursements and net changes resulting from operating, financing, and investing activities. The Statements of Cash Flows provide insight into what generates cash, where the cash comes from, and purpose of cash activity.

The Notes to Financial Statements present disclosures that contribute to the understanding of the material presented in the financial statements. This includes, but is not limited to, Schedule of Outstanding Long-Term Debt and Debt Service Requirements (See Note 4 to the Financial Statements), accounting policies, significant balances and activities, material risks, commitments and obligations, and subsequent events, if applicable.

The basic Financial Statements of each business unit along with the Notes to the Financial Statements and Management Discussion and Analysis should be used to provide an overview of Energy Northwest's financial performance. The following discussion provides comparative financial information for the years ended June 30, 2022, and 2021. Questions concerning any of the information provided in this report should be addressed to Energy Northwest at PO Box 968, Richland, WA, 99352.

## Combined Financial Information - June 30, 2022 and 2021 (Dollars in thousands)

| | | 2021 | | 2022 | | Change |
|---|---|---|---|---|---|---|
| Assets | | | | | | |
| Current Assets * | $ | 423,556 | $ | 392,097 | $ | (31,459) |
| Restricted Assets | | | | | | |
| Debt Service Funds | | 370,962 | | 372,965 | | 2,003 |
| Pension Asset | | - | | 127,200 | | 127,200 |
| Net Plant | | 1,712,264 | | 1,715,326 | | 3,062 |
| Nuclear Fuel | | 553,950 | | 477,304 | | (76,646) |
| Long-Term Receivables * | | 4,122 | | 2,440 | | (1,682) |
| Other Charges | | 3,862,353 | | 3,910,131 | | 47,778 |
| TOTAL ASSETS | | 6,927,207 | | 6,997,463 | | 70,256 |
| DEFERRED OUTFLOWS OF RESOURCES | | 695,738 | | 798,094 | | 102,356 |
| TOTAL ASSETS AND DEFERRED OUTFLOWS | $ | 7,622,945 | $ | 7,795,557 | $ | 172,612 |
| | | | | | | |
| Current Liabilities | $ | 365,988 | $ | 293,683 | $ | (72,305) |
| Restricted Liabilities | | | | | | |
| Debt Service Funds | | 118,655 | | 118,035 | | (620) |
| Long-Term Debt | | 5,426,365 | | 5,446,783 | | 20,418 |
| Other Long-Term Liabilities | | 1,657,407 | | 1,756,682 | | 99,275 |
| Other Credits | | 8,198 | | 9,141 | | 943 |
| Net Position | | | | | | |
| Invested in capital assets, net of related debt | | (20,457) | | (14,661) | | 5,796 |
| Restricted for debt service, net | | 20,720 | | 20,796 | | 76 |
| Restricted for pension asset, net | | - | | 7,733 | | 7,733 |
| Unrestricted, net | | 3,942 | | (5,292) | | (9,234) |
| TOTAL LIABILITIES AND NET POSITION | | 7,580,818 | | 7,632,900 | | 52,082 |
| DEFERRED INFLOWS OF RESOURCES * | | 42,127 | | 162,657 | | 120,530 |
| TOTAL LIABILITIES, NET POSITION AND DEFERRED INFLOWS | $ | 7,622,945 | $ | 7,795,557 | $ | 172,612 |
| | | | | | | |
| Operating Revenues * | $ | 559,915 | $ | 460,048 | $ | (99,867) |
| Operating Expenses | | 451,869 | | 389,567 | | (62,302) |
| Net Operating Revenues | | 108,046 | | 70,481 | | (37,565) |
| Other Income and Expenses * | | (105,145) | | (66,270) | | 38,875 |
| Capital Contribution | | 2,724 | | 160 | | (2,564) |
| Beginning Net Position | | (1,420) | | 4,205 | | 5,625 |
| ENDING NET POSITION * | $ | 4,205 | $ | 8,576 | $ | 4,371 |

* Energy Northwest's 2021 Statement of Net Position and Statements of Revenues and Expenses and Changes in Net Position were updated for the impacts of the required retroactive application of GASB 87 "Lease Accounting" which became effective for Energy Northwest in fiscal year 2022. See Note 1 for a summary of this change in accounting principle.

## Columbia Generating Station

Columbia Generating Station (Columbia) is wholly owned by Energy Northwest and its participants and operated by Energy Northwest. The plant is a 1,174-megawatt electric (MWe, Design Electric Rating, net) boiling water nuclear power plant located on the Department of Energy's (DOE) Hanford Site north of Richland, Washington.

Columbia produced 9,990 gigawatt-hours (GWh) of electricity in FY 2022, which included 172 GWh of economic dispatch credit, as compared to 8,842 GWh, with inclusion of credits for economic dispatch and coast down, of electricity in FY 2021. The 172 GWh of economic dispatch in FY 2022, as well as the 86 GWh of economic dispatch in FY 2021 was granted by the Bonneville Power Administration (BPA). The 131 GWh of coast down credit in FY 2021 was approved by the Executive Board (coast down credit is a prudent utility practice to optimize fuel efficiency as part of General Electric's fuel design). The request by BPA is for grid reliability and supply and, in Columbia's instance, was a result of high spring river runoff. BPA did not grant credit to Columbia in FY 2021 to overall generation as a result of management directed coast down decisions.

Columbia continues to benefit from the MWe gained because of the work performed in the last four outages starting in FY 2015 through FY 2021, which has allowed Columbia to be able to deliver an additional ~25 MWe to the grid.

Columbia's cost performance is measured by the cost of power indicator. The cost of power for FY 2022 was 3.53 cents per kilowatt-hour (kWh) as compared with 4.92 cents per kWh in FY 2021. The generating cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. The FY 2022 cost of power decrease of 28.3% was due to the increased generation levels due to FY 2022 being a non-outage year, as compared to FY 2021 being a refueling outage year.

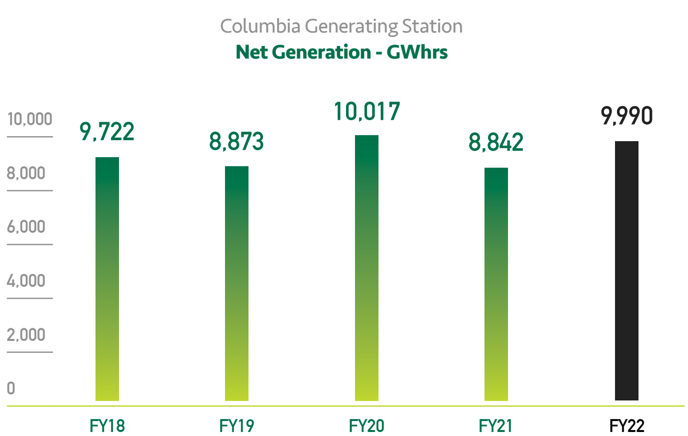
**Assets, Liabilities, and Net Position Analysis**

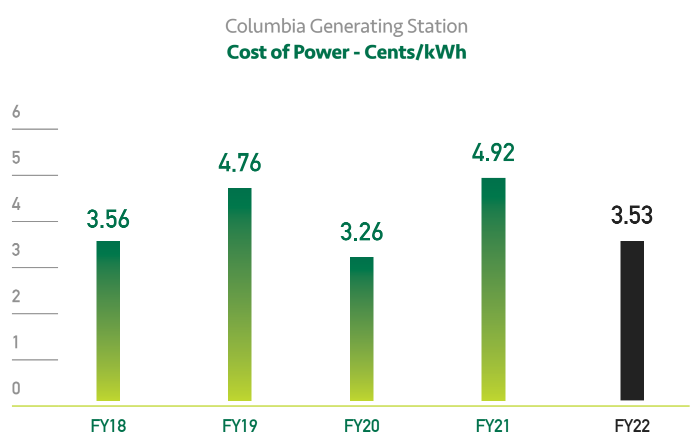
The net increase to Utility Plant (plant) and Construction Work in Progress (CWIP) from FY 2021 to FY 2022 (excluding nuclear fuel) was $6.5 million. FY 2021 Plant has been restated for comparison purposes to include the retroactive application of GASB 87 "Lease Accounting", which become effective for Energy Northwest at the beginning of FY 2022 (See Notes 1 and 13). The changes to plant and CWIP were comprised of additions to plant of $131.7 million and a decrease to CWIP of $31.9 million. Remaining change was the period effect of depreciation of $92.5 million of plant assets and $0.8 million of lease asset depreciation.

The FY 2022 CWIP balance of $36.2 million consisted of six major projects of at least $0.5 million: Main Steam Isolation Valve Disassemble and Inspection, Moisture Separator Reheater Internals Retrofitting, High Pressure Turbine Replacement, Adjustable Speed Drive Replacement, Independent Spent Fuel Cask Purchases, and Independent Spent Fuel Pad Expansion. These projects over $0.5 million result in 94.6% of the current CWIP balance. The remaining 5.4% of CWIP is comprised of 30 separate projects.

Nuclear fuel, net of accumulated amortization, decreased $76.6 million from FY 2021 to $477.3 million in FY 2022. During FY 2022 Columbia incurred $36.7 million in capitalized fuel/reload activity. A decrease to spent fuel of $95.4 million reflects the original cost of fuel assemblies removed from R-25 and past the required six-month cooling period per the Federal Energy Regulatory Commission (FERC) guidelines. Accumulated fuel burnup amortization decreased $44.5 million due to the net of the fuel burnup amortization for the fuel assemblies removed from R-25 and the FY 2022 fuel burnup amortization. A decrease of $62.4 million occurred related to TVA Fuel activity. (See Note 11).

The FY 2021 current asset balance has been restated for comparison purposes to include the retroactive application of GASB 87 at the beginning of FY 2022 (See Notes 1 and 13).



Current assets decreased $28.8 million in FY 2022 to $328.1 million. The changes were decreases to cash and investments of $29.6 million and a decrease in receivables of $0.7 million. The current asset decreases were offset by an increase to prepayments of $0.1 million and an increase to materials and supplies of $1.4 million.

Restricted assets increased $122.3 million to $426.7 million in FY 2022. The changes were increases to pension asset in accordance with GASB No. 68, of $118.4 million (See Note 6) and $3.9 million increase due to the FY 2022 bond funding activities and bond restructuring associated with the regional cooperation debt program.

Non-current assets FY 2021 balance has been restated for comparison purposes to include the retroactive application of GASB 87 at the beginning of FY 2022 (See Notes 1 and 13). Non-current lease receivable decreased $0.4 million to $2.0 million in FY 2022.

Other charges increased $46.9 million from $1,941.3 million in FY 2021 to $1,988.2 million in FY 2022. The increase was Costs in Excess of Billings related to the net effect of payment of current maturities and refunding activity associated with the regional cooperation debt program.

Deferred outflows increased $101.1 million in FY 2022 from $686.6 million to $787.7 million. The changes were an increase $104.1 million asset retirement adjustment ($103.7 million - Columbia, $0.4 million - ISFSI) due to requirements of GASB No. 83 (See Note 9). The increases were offset by a decrease of $1.6 million due to the recognition of a deferred pension outflow in accordance with GASB No. 68 (See Note 6) and a $1.4 million decrease to unamortized loss on refunding associated with the 2022 bond activity.

Current liabilities decreased $69.0 million in FY 2022 to $242.6 million. The change included a decrease in the current line of credit of $20.0 million in FY 2022 to $65.9 million. Other decreases included accounts payable of $31.6 million, a decrease in accrued expenses of $8.0 million, which includes the current lease liability recognized due to the retroactive application of GASB 87 at the beginning of FY 2022 (See Notes 1 and 13), and a decrease in due to other business units of $4.8 million, which are a timing result of year-end obligations. Other decreases from timing of due to participants resulted in a decrease of $5.0 million. Offsetting the decreases was an increase in current maturities of long-term debt of $0.4 million per the maturity schedule for bonds.

Restricted liabilities decreased $0.8 million in FY 2022 to $74.1 million reflecting the changes in accrued interest on various bond series.

Long-term debt (Bonds Payable) increased $34.3 million in FY 2022 from $3,464.8 million to $3,499.1 million due to the FY 2022 bond restructuring and funding activities associated with the regional cooperation debt program.

Other long-term liabilities increased $99.6 million in FY 2022 to $1.727 billion. The major driver was increases to the asset retirement obligation due to GASB No. 83. Decommissioning liability increased $133.3 million due to required yearly indexing of the obligation. Columbia accounted for $132.6 million of the increase and ISFSI accounted for $0.7 million of the increase. The establishment of the other postemployment benefits liability resulted in an increase of $0.2 million in accordance with GASB No. 75. Offsetting the increases was a pension liability decrease of $33.2 million in accordance with GASB No. 68. FY 2021 other long-term liabilities has been restated for comparison purposes due to the retroactive application of GASB 87 at the beginning of FY 2022 (See Notes 1 and 13), which resulted in a $0.7 million decrease to $4.6 million in FY 2022.

Costs associated with cask activity are no longer being recorded as a long-term liability as all costs have been deemed reimbursable under the agreement with DOE and reimbursements, per each approved submittal, will be offset against costs incurred (See Note 11).

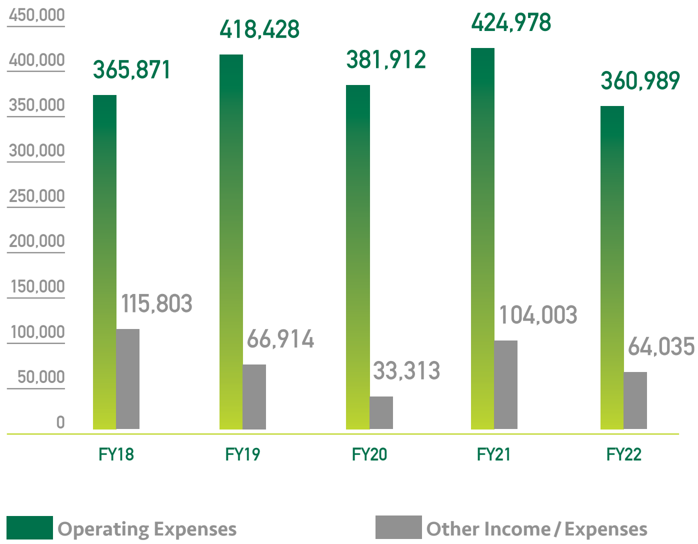
Deferred inflows increased $106.9 million from $27.2 million in FY 2021 to $134.1 million in FY 2022. An increase of $109.0 million was recognized to deferred pension inflow in accordance with GASB No. 68. FY 2021 deferred inflows has been restated for comparison purposes due to the retroactive application of GASB 87 at the beginning of FY 2022 (See Notes 1 and 13), which resulted in a deferred lease inflow decrease of $1.9 million to $2.4 million in FY 2022. A decrease to bond refunding inflows of $0.2 million was due to the FY 2022 bond restructuring and funding activities associated with the regional cooperation debt program. Deferred credits for FY 2022 consisted of unclaimed bearer bonds and remained at the same level as FY 2021.

**Revenue and Expenses Analysis**

Columbia is a net-billed project. Energy Northwest recognizes revenues equal to expenses for each period on net-billed projects. No net revenue or loss is recognized, and no net position is accumulated.

Operating expenses decreased $64.0 million from FY 2021 costs of $425.0 million to $361.0 million in FY 2022. The major decrease in costs was due to FY 2022 being a non-refueling year as compared to FY 2021 being a refueling year (R-25). The decrease in FY 2022 was in the operations and maintenance area ($57.4 million) due to FY 2022 being a non-refueling year. Administration and general expenses decreased $22.3 million in FY 2022. The administrative and general expenses changes include a decrease in pension expenses of $19.7 million related to GASB No. 68 and benefits liquidation expense decreases of $3.6 million, offset by miscellaneous other administration and general expenses of $1.0 million. Offsetting the decreases were increases in decommissioning of $3.3 million due to annual indexing requirements of the obligation related to

Columbia Generating Station
**Total Operating Costs (Dollars in thousands)**




GASB No. 83. Also, increases in nuclear fuel and generation taxes of $4.6 million and $0.7 million, respectively, due to increased generation. Finally, there was an increase of $7.1 million for depreciation and amortization due to more plant assets being placed in-service.

Other Income and Expenses decreased $40.0 million from FY 2021 to $64.0 million net expenses in FY 2022. A gain of $21.1 million was recognized in FY 2022 on the spent fuel litigation settlement from the DOE, which was $12.8 million more than FY 2021. The cask costs were never an intended cost for the facility and only resulted from a failure to perform from the Department of Energy (See Note 10). Fuel disposal is no longer being recognized as part of the DOE settlement for this reason and any future recoveries from the DOE will be recorded in similar fashion. Another component of the change was a gain on the scheduled Separative Work Units (SWU) sale related to the TVA fuel contract (See Note 11). The FY 2022 gain on SWU sale was $23.5 million and is an increase over FY 2021 since there was not a sale of SWU in FY 2021. In FY 2022, there was a decrease of $0.2 million in Build American Bonds revenue as compared to FY 2021. Bond interest expenses and amortization costs of $113.2 million were incurred as part of the FY 2022 planned and approved regional cooperation debt program, however, these were lower in FY 2022 by $5.4 million as compared to FY 2021. The net lease activity from the retroactive application of GASB 87 for lease revenue, lease expense resulted in a $0.2 million in expense in FY 2022 (See Notes 1 and 13). There was $0.9 million less in lease revenue for building leases not subject to GASB87 as compared to FY 2021. There was $0.2 million less spent on building modifications for tenants in FY 2022 as compared to FY 2021. The remaining change of $0.6 million was due to decreases in investment income for FY 2022 as compared to FY 2021.

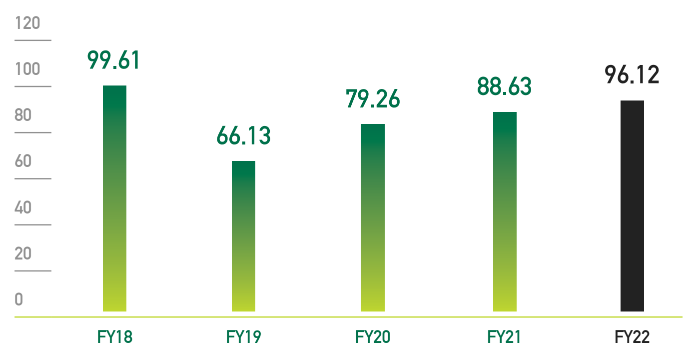
Columbia's total operating revenue decreased from $527.7 million in FY 2021 to $425.0 million in FY 2022. The decrease of $102.7 million was due to the off-cycle year of the two-year refueling plan and the related effect of the net billing agreement on total revenue (See Note 5).

In FY 2022 Columbia received $11 thousand of contributed capital towards the Advanced Remote Monitoring project as compared to $1.3 million received in FY 2021. Energy Northwest entered into an agreement with the Utilities Service Alliance, who received a grant from the Department of Energy, to develop an Advanced Remote Monitoring system for nuclear plants.

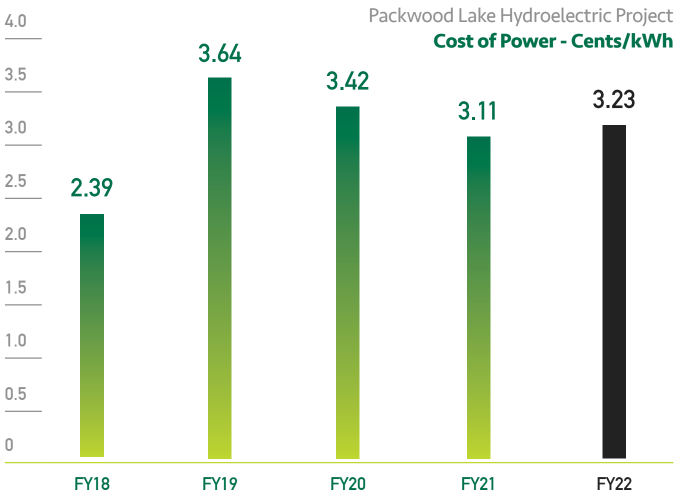
## Packwood Lake Hydroelectric Project

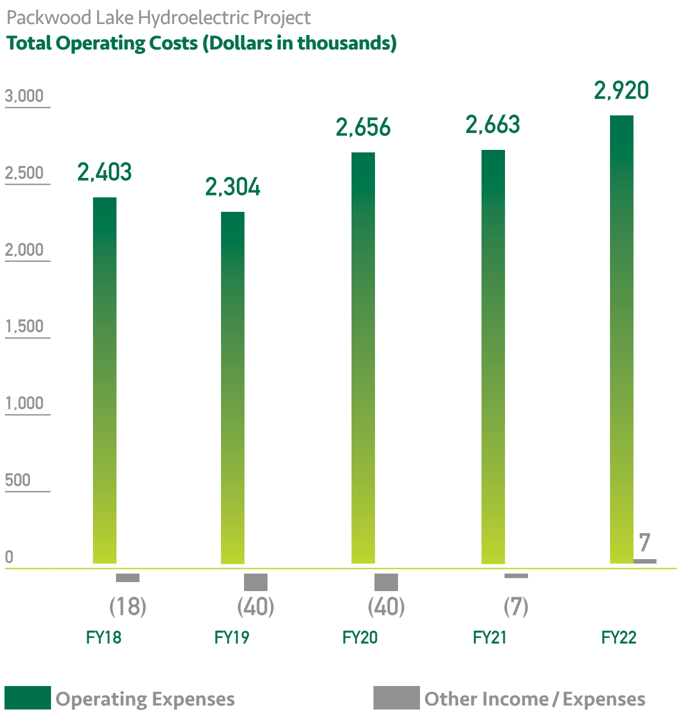
The Packwood Lake Hydroelectric Project (Packwood) is wholly owned and operated by Energy Northwest. Packwood consists of a diversion structure at Packwood Lake and a powerhouse located near the town of Packwood, Washington. The water is carried from the lake to the powerhouse through a five-mile long buried tunnel and drops nearly 1,800 feet in elevation. Packwood produced 96.12 GWh of electricity in FY 2022 versus 88.63 GWh in FY 2021. The generation increase of 8.5% was mostly due to FY 2021 being the twenty-first lowest generation year on record. In FY 2022, Packwood's generation exceeded the last five-year average net generation of 86.37 GWh. The generation for FY 2022 was above the life to date average per year of 93.90 GWh.

Packwood Lake Hydroelectric Project
**Net Generation - GWhrs**




Packwood had been operating under a fifty-year license issued by FERC, which expired on February 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on February 22, 2008. On March 4, 2010, FERC issued a one-year extension to operate under the original license, which indefinitely extended for continued operations until a formal decision was issued by FERC and a new operating license granted. On March 21,




2018, the National Oceanic and Atmospheric Administration/ National Marine Fisheries Service (NOAA/NMFS) filed to the FERC the Biological Opinion (BiOp) of the Endangered Species Act for the relicensing of Packwood. On October 11, 2018, FERC issued the forty-year operating license effective October 1, 2018 (See Note 1 to the Financial Statements). The relicensing cost of $3.7 million incurred in previous years was transferred to intangible plant in FY 2019 and is being amortized over the forty-year license issued October 2018.

Packwood's cost performance is measured by the cost of power indicator. The cost of power for FY 2022 was $3.23 cents per kWh as compared to $3.11 cents per kWh in FY 2021. The cost of power fluctuates year-to-year depending on various factors such as outage, maintenance, generation, and other operating costs. The increase (3.9%) in the FY 2022 cost of power was driven by additional costs ($0.3 million) for an upgrade to the interconnection between Packwood and Lewis County Public Utility District's transmission lines. The increased cost was partially offset by the increase in generation noted previously.

**Assets, Liabilities, and Net Position Analysis**

Total assets and deferred outflows increased $0.9 million in FY 2022. The net increase to Plant from FY 2021 to FY 2022 was $0.3 million. The increase to plant was offset by the period effect of depreciation of $0.3 million. FY 2021 Plant has been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Current assets increased $58 thousand due to timing of due from other business units offset by the timing of cash and investments activity at the end of the fiscal year. Restricted assets increased $0.6 million due to the establishment of a pension asset in accordance with GASB No. 68 (See Note 6). Also, there was a $22 thousand increase to deferred pension outflow as part of the requirements of GASB No. 68 (See Note 6) and there was no change to the recognition of other postemployment benefit outflow in accordance with GASB No. 75 in FY 2022.

Total liabilities, net position and deferred inflows increased $0.9 million in FY 2022. There was an increase to other credits of $0.9 million related to billings in excess of costs. FY 2021 Current and non-current liabilities have been restated for comparison purposes to include the retroactive application of GASB 87, which became effective at the beginning of FY 2022 (See Notes 1 and 13). Current liabilities decreased $0.4 million, pension liability decreased $53 thousand, other postemployment benefit liability increased $1 thousand, and there was an increase to deferred pension inflow of $0.4 million. Pension deferrals and pension liability are recognized in accordance with GASB No. 68 and the other postemployment benefit deferrals, and liability are recognized in accordance with GASB No. 75.

**Revenue and Expenses Analysis**

The agreement with Packwood participants obligates them to pay annual costs and to receive excess revenues. (See Note 1 to the Financial Statements.) Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no net position is accumulated. Operating expenses increased $0.3 million in FY 2022 as compared to FY 2021, which is due to the previously mentioned upgrade to the interconnection between Packwood and Lewis County Public Utility District's transmission lines.

Other Income and Expense comprised of the lease activity from the retroactive application of GASB 87 for lease expense and related interest decreased $11 thousand in FY 2022 (See Notes 1 and 13) and investment income decreased $3 thousand from FY 2021 to a total of $4 thousand for FY 2022.

Packwood participants are obligated to pay annual costs of the project (including any applicable debt service), whether or not the project is operable. The Packwood participants also share project revenue to the extent that the amounts exceed costs. These funds can be returned to the participants or kept within the project. As of June 30, 2022, there is $8.6 million recorded as other credits that are deferred billing in excess of costs being kept within the project. Packwood participants are currently taking 100% of the project generation; there are no additional agreements for power sales.

## Nuclear Project No. 1

Energy Northwest wholly owns Nuclear Project No. 1, a 1,250-MWe plant, which was placed in extended construction delay status in 1982, when it was 65% complete. On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 1. All funding requirements are net-billed obligations of Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity of Nuclear Project No. 1 and are net-billed (See Notes 5 and 10).

**Assets, Liabilities, and Net Position Analysis**

FY 2021 total assets and deferred outflows has been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Total Assets and deferred outflows decreased $0.6 million from $916.1 million in FY 2021 to $915.5 million in FY 2022. The change was due to a net decrease of $0.1 million in Plant, a decrease of $0.6 million in current receivables, a decrease of $0.5 million in due from other business units, and a decrease of $0.5 million in costs in excess of billings, offset by an increase of $0.4 million in debt service funds from bond activity, an increase of $0.5 million in recognition of a pension asset in accordance with GASB No. 68 (See Note 6), and an increase of $0.2 million from cash and investment activity. Deferred pension outflows increased $21 thousand due to the recognition of a deferred pension outflow in accordance with GASB No. 68 (See Note 6), and a decrease of $1 thousand to the recognition of other postemployment benefit outflow in accordance with GASB No. 75.

Long-term debt increased $9.8 million from $782.9 million in FY 2021 to $792.7 million in FY 2022 offset with a decrease related to debt discounts/premiums of $14.5 million. The overall change in long-term debt was due to debt activity associated with the planned and approved regional cooperation debt program. Total restricted liabilities increased $0.1 million from $19.6 million in FY 2021 to $19.7 million in FY 2022, which is an increase in total accrued interest payable on long-term debt (See Note 1). FY 2021 current liabilities have been restated for comparison purposes to include the application of GASB 87 (See Notes 1 and 13). Current liabilities decreased $0.7 million due to a $1.1 million decrease in accounts payable and accrued expenses, offset by an increase of $0.4 million in current maturities of debt. FY 2021 total long-term liabilities have been restated for comparison purposes to include the application of GASB 87 (See Notes 1 and 13). Total long-term liabilities decreased $2.3 million, which mostly consisted of a decrease of $2.2 million to decommissioning liability to $4.0 million for the asset retirement obligation per GASB No. 83 (See Note 9), a decrease of $40 thousand in pension liability per GASB No. 68 (See Note 6), and a $46 thousand decrease in long-term lease liability per GASB 87 (See Notes 1 and 13), offset by an increase of $1 thousand due to the recognition of other postemployment benefit outflow in accordance with GASB No. 75. Deferred inflows increased $7.0 million from $13.6 million in FY 2021 to $20.6 million in FY 2022. The changes are due to an increase of $6.6 million in deferred inflows for unamortized gain on bond refunding and a $0.4 million increase in deferred pension inflows recognized in accordance with GASB 68 (See Note 6). There were no major changes in the balance for deferred credit.

**Revenue and Expenses Analysis**

Other Income and Expenses showed a net increase to expenses of $3.0 million from $20.2 million in FY 2021 to $23.2 million in FY 2022. Main driver for the change was an increase to the decommissioning estimate of $4.4 million. The decommissioning change in estimate was per GASB No. 83 (See Note 9). The other changes included a decrease on $0.1 million in plant preservation and termination costs and a decrease to bond related interest expense and amortization of $1.3 million.

## Nuclear Project No. 3

Nuclear Project No. 3, a 1,240-MWe plant, was placed in extended construction delay status in 1983, when it was 75% complete. On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 3. Energy Northwest is no longer responsible for any site restoration costs as they were transferred with the assets to the Satsop Redevelopment Project. The debt service-related activities remain the responsibility of Energy Northwest and are net-billed (See Notes 5 and 10).

**Assets, Liabilities, and Net Position Analysis**

Current assets stayed steady at $3.2 million in FY 2022. Debt service funds decreased $2.1 million from $25.0 million in FY 2021 to $22.9 million in FY 2022 from bond activity. Other charges increased $1.3 million from $1,029.8 million in FY 2021 to $1,031.1 million in FY 2022. The increase was costs in excess of billings related to the net effect of payment of current maturities and refunding activity associated with the regional cooperation debt program.

Long-term debt increased $18.5 million from $926.3 million in FY 2021 to $944.8 million in FY 2022 offset by a decrease related to debt discounts/premiums on debt activity during the year of $17.2 million. The overall change in long-term debt was due to debt activity associated with the planned and approved regional cooperation debt program. Total restricted liabilities increased $0.3 million from $22.7 million in FY 2021 to $23.0 million in FY 2022, which is an increase in total accrued interest payable on long-term debt (See Note 1). Current debt per the debt maturity schedule decreased $2.4 million per the planned and approved regional cooperation debt program There were no significant changes in deferred credits.

**Revenue and Expenses Analysis**

Overall expenses and revenues increased slightly by $0.4 million in FY 2022 due to increased interest expense and bond amortization costs.

## Business Development Fund

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. The Business Development Fund (BDF) was created by Executive Board Resolution No. 1006 in April 1997, for the purpose of holding, administering, disbursing, and accounting for Energy Northwest costs and revenues generated from engaging in new business opportunities.

The BDF is managed as an enterprise fund. Five business sectors have been created within the fund: Business Support, Energy & Professional Services, Laboratory Support, Nuclear Development and Operation & Maintenance Services. A separate line of activity is used as general business unit support. Each line may have one or more programs that are managed as a unique business line activity.

**Assets, Liabilities, and Net Position Analysis**

FY 2021 Total assets and deferred outflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Total assets and deferred outflows increased $7.3 million from $23.8 million in FY 2021 to $31.1 million in FY 2022. There was an increase of $6.6 million to restricted assets for the recognition of a pension asset in accordance with GASB No 68 (See Note 6), an increase to current assets of $0.2 million, an increase to deferred pension outflow of $0.5 million in accordance with GASB No. 68 and an increase of $19 thousand due to the recognition of other postemployment benefit outflow in accordance with GASB No. 75.

FY 2021 Total Liabilities, Net Position and Deferred Inflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Total liabilities, net position and deferred inflows increased $7.3 million. Current liabilities increased $0.4 million from FY 2021 due to timing of year-end outstanding items. Long-term liabilities decreased $0.4 million due to a $0.4 million decrease in net pension liability in accordance with GASB No. 68. Deferred inflows increased $5.2 million to account for the change in net pension liability. The change in net position of $2.1 million is the net of $3.4 million from operations in FY 2022 reflected in the activities described below, continuing margin achievement on business sector activity, $0.1 million in contributed capital from the Electric Vehicle project, and a $1.4 million impact due to the recognition of pension expense.

**Revenue and Expenses Analysis**

Operating Revenues in FY 2022 totaled $14.2 million as compared to FY 2021 revenues of $11.9 million, an increase of $2.3 million (19.3%). Various projects and timing of work were drivers for the increase in overall revenue for the BDF and the five business sectors.

- The Business Support sector revenues remained relatively steady in FY 2022, with a slight increase from $40 thousand in FY 2021 to $47 thousand in FY 2022. The sector remains steady based on continued rental agreements.

- The Energy & Professional Services sector revenues increased $0.3 million in FY 2022 from $0.9 million in FY 2021 to $1.2 million. The increase in this sector was due to the following:

  Energy Northwest received two grant awards in 2022 for building eight new charging stations along the White Pass Scenic Byway. The first grant is from the Washington State Department of Commerce's Clean Energy Fund and the second grant is from the TransAlta Coal Transition Fund. Energy Northwest is reporting $140 thousand of contributed capital from the Washington State Department of Commerce grant and $9 thousand of contributed capital from the TransAlta grant. Energy Northwest continues to seek and apply for grant funding to install electric vehicle charging stations as well as support electric utilities in the Pacific Northwest in their efforts to install electric vehicle charging stations and advance electric vehicle adoption.

  In FY 2022, there was a $0.2 million decrease in revenues related to the Electric Vehicle Infrastructure Transportation Alliance Project (EVITA), as there was not any grant funding received for this project in FY 2022 as compared to $0.2 million in FY 2021. For the operation and maintenance of charging stations that were installed in prior years as part of the EVITA project, Energy Northwest received $5 thousand in FY 2022.

In 2021, Energy Northwest entered a lease option agreement with Tucci Energy Services, for the purpose of developing a solar project on undeveloped land located approximately 3 miles north of Richland. The lease option agreement included the option of leasing up to 300 acres of the unused land for future development. This land is part of 300 acres Energy Northwest purchased from Tri-City Development Council (TRIDEC) in 2016 for future development. This lease option resulted in a decrease of $3 thousand in revenue from FY 2021 to $12 thousand in FY 2022.

Energy Northwest was the recipient of a Washington State Department of Commerce (Commerce) grant in 2015, which was finalized in 2017. The Commerce grant was an award of up to $3.0 million under the Washington Clean Energy Funds' Grid Modernization Grant Program. The grant was to develop the Horn Rapids Solar Storage and Training (HRSST) project. The HRSST project included the development of a 4 MWdc photovoltaic solar project coupled with a 1MW/4 MWh basic lithium ion battery storage. Energy Northwest collaborated and came to agreement with the City of Richland for the Battery Energy Storage System (BESS) storage portion of the HRSST. The Energy Northwest Board of Directors approved the project, and The City of Richland signed a participant agreement in October of 2018. Construction of the BESS was initiated in FY 2020 and both the solar project (Energy Northwest does not own the solar portion of the project) and BESS, were completed in FY 2021 and the project is now operational. The project costs were approximately $6.4 million through FY 2021 and $64 thousand in FY 2022. Energy Northwest is reporting $0 in contributed capital and $64 thousand in revenue for FY 2022, as compared to $1.4 million in contributed capital and $0 in revenue for FY 2021.

Information Technology (IT) and Cyber Security Services decreased $0.3 million from $0.5 million in FY 2021 to $0.2 million in FY 2022. The decrease in IT revenues is mainly due to less services being provided under a services contract between Energy Northwest and Mission Support Alliance to update information technology equipment at the HAMMER training facility in Richland, Washington, resulting in $0.4 million decrease. The decrease was offset by several new IT and Cyber Security Services contracts in FY 2022, which provided $0.1 million in revenue.

In FY 2021, Energy Northwest created an internship program, in which Energy Northwest is identifying engineering students looking for internship opportunities, then provides the names and resumes to Energy Northwest Member utilities that are participating in the program. The Energy Northwest Member utilities then can interview the students and offer internships. This program' revenues stayed flat at $0.1 million for FY 2022.

In FY 2022, Energy Northwest entered into an agreement with Bechtel National to provide maintenance on laboratory equipment, which resulted in an increase in revenues of $0.7 million.

- The Laboratory Support sector increased $0.4 million in FY 2022 from $6.3 million in FY 2021 to $6.7 million, a 7.9% increase. The increase in revenue is a result of the Calibration Laboratory receiving additional work from existing customers and new customers; also, the Environmental Laboratory provided additional services to Columbia in FY 2022.

- The Nuclear Development sector increased $2.6 million in FY2022 from $0.4 million to $3.0 million. The change in this sector was due to the following:

  Energy Northwest entered into a teaming agreement with NuScale Power and Utah Associated Municipal Power Systems (UAMPS) as part of the Western Initiative for Nuclear project collaboration to promote a commercial, small modular reactor (SMR) in the western United States. NuScale Power, located in Corvallis, Oregon is poised to supply the facility for the Carbon-Free Power Project (CFPP). NuScale is working with UAMPS to site the CFPP at the Idaho National Laboratory in Idaho Falls, Idaho. Revenues for the CFPP declined $5 thousand from $5 thousand in FY 2021 to $0 in FY 2022.

  In October 2020, the Department of Energy announced it had selected X-energy and TerraPower-GE Hitachi for its Advanced Reactor Demonstration Program (ARDP), which provides initial funding for two domestic advanced nuclear reactor projects. Energy Northwest was listed as a utility partner on both applications. In April 2021, Energy Northwest, X-energy and Grant County Public Utility District (PUD) signed a Tri Energy Partnership agreement to evaluate, develop and build a commercial Xe-100 advanced reactor. During FY 2022, Energy Northwest provided services to X-energy, which resulted in $2.9 million in revenues, which is an increase of $2.5 million over FY 2021. Also, during FY 2022, Energy Northwest provided services to Grant County PUD to assist in their evaluation under the TRi Energy Partnership agreement, which resulted in an increase of $86 thousand in revenue. Energy Northwest provided services to TerraPower-GE Hitachi in FY 2022 as part of the ARDP, which resulted in an increase of $39 thousand in revenue.

- The Operations & Maintenance sector supports public power in the areas of operations and maintenance of generating facilities and electric utility automation. Revenues from the Operations & Maintenance business sector decreased $1.0 million from $4.3 million in FY 2021 to $3.3 million in FY 2022, a decrease of 23.3%.

  Work at the Portland Hydro Project remained steady from previous year with revenues at $1.4 million for both FY 2022 and FY 2021. Portland Hydro is a five-year agreement for operating and maintaining two powerhouses on the Bull Run River for the City of Portland, the agreement runs through FY 2023.

  The Tieton Hydroelectric Project revenues decreased $1.0 million in FY 2022 to $1.3 million as compared to $2.3 million for FY 2021. The Tieton project is a year to year agreement for operating and maintaining the 25 MW project located at Rimrock Lake in Yakima County, Washington owned by City of Burbank.

  Energy Northwest entered into an agreement with Eugene Water and Electric Board (EWEB) to operate and maintain the Stone Creek Hydro project located on the Oak Grove Fork of the Clackamas River. The agreement is for a five-year period to maintain the 12 MWe project for EWEB and was signed in May of 2020. Revenues decreased $35 thousand for FY 2022 to $443 thousand as compared to $478 thousand for FY 2021.

  Energy Northwest entered into an agreement in FY 2021 with Idaho Water & Resources Board (IWRB) to operate and maintain the Dworshak Small Hydroelectric Project located near Orofino, Idaho on the Clearwater River and supplies water to the nearby Dworshak National Fish Hatchery. The agreement was for a nine-month period to maintain the 3 MWe project for IWRB was signed in July of 2020. This contract was not renewed in FY 2022, resulting in a decrease in revenues of $59 thousand as compared to FY 2021.

Operating costs increased $1.5 million from $10.7 million in FY 2021 to $12.2 million in FY 2022, which was a 14.0% increase in overall operating costs. The operating costs for Operations and Maintenance increased $2.5 million (11.0%) from $10.1 million in FY 2021 to $12.7 million in FY 2022. These costs correlate with the increases in project related revenues mentioned above. Also, there was increase in depreciation expense of $0.4 million from $0.3 million in FY 2021 to $0.7 million in FY 2022, this increase is due to plant placed in service increases at the end of FY 2021. Offsetting the increases is a decrease in administration and general expense of $1.4 million due to a decrease in the pension expense related to GASB No. 68.

Other Income and Expenses decreased $129 thousand in FY 2022 to a net expense of $56 thousand. The overall decrease was due to lower investment returns of $161 thousand, higher income from net lease activities including lease income and expense and lease interest income and expense of $4 thousand, and increased amounts of grant revenue $28 thousand.

The BDF previously received contributions from the Internal Service Fund to cover cash needs during startup periods. Initial startup costs were not expected to be paid back and are shown as contributions. As an operating business unit, requests can be made to fund incurred operating expenses. In FY 2021, the Energy Northwest Executive Board approved the contribution of $4.4 million from the Internal Service Fund, which eliminated the excess contributed funds in the Internal Service Fund, so there will not be any contributions in the future.

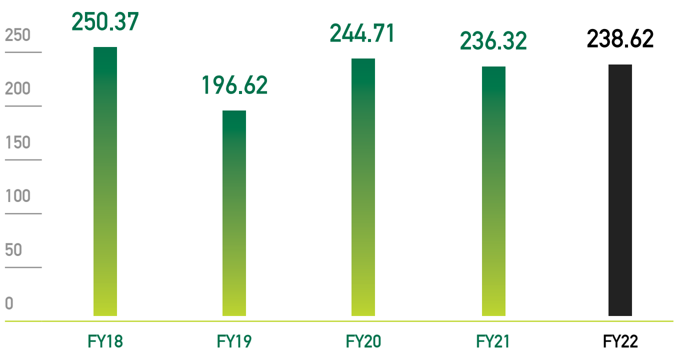
## Nine Canyon Wind Project

The Nine Canyon Wind Project (Nine Canyon) is wholly owned and operated by Energy Northwest. Nine Canyon is located in the Horse Heaven Hills area southwest of Kennewick, Washington. Electricity generated by Nine Canyon is purchased by Pacific Northwest Public Utility Districts (purchasers). Each of the purchasers of Phase I, Phase II, and Phase III have signed a power purchase agreement which are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Purchase Agreement which now has an end date of 2030. Nine Canyon is connected to the BPA transmission grid via a substation and transmission lines constructed by Benton County Public Utility District.

Phase I of Nine Canyon, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 MW, for an aggregate generating capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 12 wind turbines, each with a maximum generating capacity of 1.3 MW, for an aggregate generating capacity of approximately 15.6 MW. Phase III of Nine Canyon, which was declared operational in May 2008, includes 14 wind turbines, each with a maximum generating capacity of 2.3 MW, for an aggregate generating capacity of 32.2 MW. The total Nine Canyon generating capability is 95.9 MW, enough energy for approximately 39,000 average homes.

Nine Canyon produced 238.62 GWh of electricity in FY 2022 versus 236.32 GWh in FY 2021. The increase of 1.0% for generation was a direct result of an increased average monthly capacity factor of 29.2% for FY 2022 versus 29.1% for FY 2021 (increase of 0.3%) and a higher average wind speed of 2.9%

Nine Canyon Wind Project
**Net Generation - GWhrs**




(15.88 miles per hour) versus FY 2021 (15.43 miles per hour). Gross Generation for FY 2022 and FY 2021 were both above the five year average gross generation for the project.

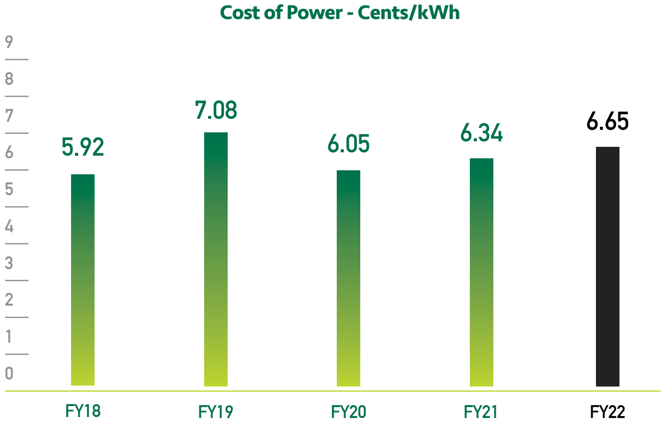
Nine Canyon's cost performance is measured by the cost of power indicator. The cost of power for FY 2022 was $6.65 cents per kWh as compared to $6.34 cents per kWh in FY 2021. The cost of power fluctuates year to year depending on various factors such as wind conditions and unplanned maintenance and is distinctly different than revenue billed cost of power discussed below in revenue and expense analysis. The cost of power does not include the Bonneville Power Administration's (BPA) Transmission costs, which are pass-through costs to the purchasers. The increase of 4.9% in cost of power for FY 2022 was attributable to increased operations and maintenance costs, excluding BPA transmission costs and increased decommissioning costs. The increased costs were offset by the increased capacity factor and favorable average wind speeds.

**Assets, Liabilities, and Net Position Analysis**

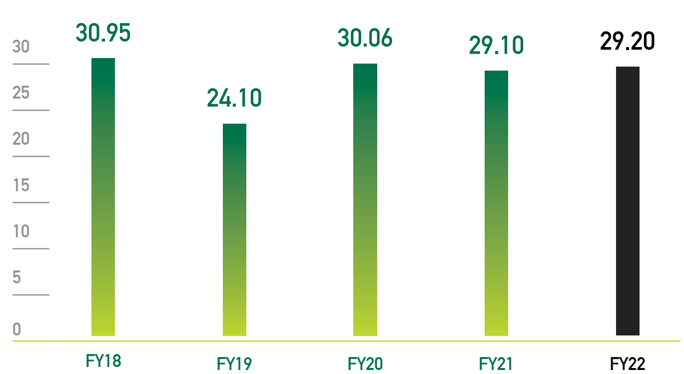
FY 2021 Total assets and deferred outflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Total assets and deferred outflows decreased $5.8 million from $72.6 million in FY 2021 to $66.8 million in FY 2022. The major driver for the change in assets was a decrease of $6.8 million in net plant due to accumulated depreciation. The remaining changes consisted of a decrease to restricted (special and debt service funds) of $0.1 million, a $1.2 million increase for the recognition of a pension asset as part of the requirements of GASB No. 68 (See Note 6), a decrease to current assets of $0.7 million. There were no significant changes to deferred pension outflow as part of the requirements of GASB No. 68 (See Note 6). Unamortized debt expense decreased $0.2 million, and an increase to deferred outflows related to the asset retirement obligation of $0.8 million due to the requirements of GASB No. 83 (See Note 9).

FY 2021 Total Liabilities, Net Position and Deferred Inflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). There was an overall decrease to liabilities, net position, and deferred inflows of $5.8 million. Changes were a decrease to long-term debt (including unamortized bond discount/premium) of $10.6 million, an increase to current maturities of debt of $0.5 million, a decrease of $0.1 million to accounts payable and accrued expenses, and a decrease of $0.2 million accrued debt service interest. Other long-term liability changes were decreases of $0.2 million for pension liability, and an increase of $1.6 million to the decommissioning liability, as a result of indexing requirements in accordance with GASB No. 83 (See Note 9). There was a $1.0 million increase to the deferred pension inflow. Pension liability and deferrals are recognized in accordance with GASB No. 68 (See Note 6). The change in net position of $2.2 million is the net of the total from net operations of $2.6 million in FY 2022, and a $0.4 million impact due to the recognition of pension expense. Although

Nine Canyon Wind Project
**Cost of Power - Cents/kWh**




Nine Canyon Wind Project
**Capacity Factor (%)**



a decrease in the year-to-year operations, FY 2022 positive results continue to reflect the results of the debt financing efforts and cost reduction/stabilization efforts.

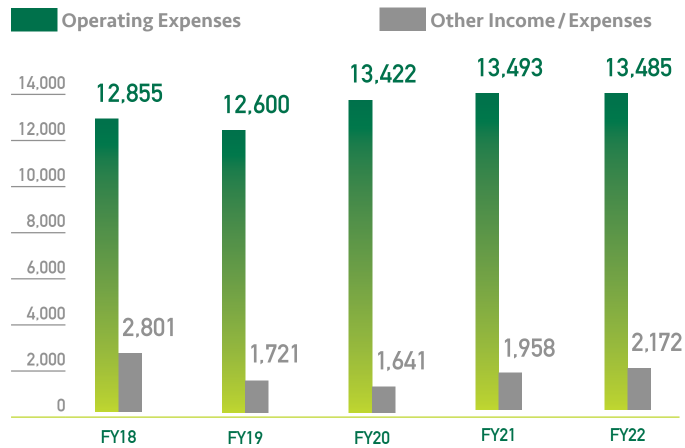
In previous years Energy Northwest has accrued, as income (contribution) from the Department of Energy, Renewable Energy Production Incentive (REPI) payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI legislation. REPI was created to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under Section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. The payment stream from Nine Canyon participants and the REPI receipts was projected to cover the total costs over the purchase agreement. Continued shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project (2030 proposed end date) in FY 2008. Results of operations, debt refunding, and generation affect the yearly rate plan. In FY 2017 Nine Canyon Participants of all three phases realized a 3% decrease in rates driven by debt refinancing efforts and cost reduction/stabilization efforts. The current rate plan remains in effect; going forward the increase or decrease in rates will be based on cash requirements of debt repayment and the cost of operations.

**Revenues and Expenses Analysis**

Operating Revenues in FY 2022 totaled $17.9 million as compared to FY 2021 revenues of $18.4 million, a decrease of $0.5 million (2.7%). The decrease in revenues is due to lower pass-through BPA Transmission costs than FY 2021. The project received revenue from the billing of the purchasers at an average rate of $76.95 per MWh for FY 2022 as compared to $80.38 per MWh for FY 2021. The decrease in the billed rates reflects the more favorable wind conditions and slightly higher average capacity and planned recovery of operating costs. The stabilization of revenue continues to reflect the implementation of the current rate plan account for costs of operations over the remaining life of the project, taking into account the REPI shortfalls in the early years of the project.

Operating expenses remained steady from FY 2021 amounts at $13.5 million in FY 2022. Operation and maintenance expenses increased $0.1 million from FY 2021 to $6.2 million in FY 2022. Also, decommissioning expense increased $0.1 million due to annual indexing requirements of the obligation related to GASB No. 83 (See Note 9). The increases were offset by a reduction of $0.2 million in the pension expense related to GASB No. 68 (See Note 6). Other income and expenses increased $0.2 million from $1.9 million in net expenses in FY 2021 to $2.1 million in FY 2022. Bond interest expense and

Nine Canyon Wind Project
**Total Operating Costs (Dollars in thousands)**




changes in amortized bond expenses decreased $0.3 million and investment income decreased $0.4 million, resulting in a net $0.4 million expense. Also, net lease activity resulting from the implementing of GASB 87 increased expenses by $0.1 million. Net income or change in net position of $2.2 million for FY 2022 was due to holding operating expenses steady.

The original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires. The REPI incentive expires 10 years from the initial operation startup date for each phase. Reserves that were established are used to facilitate this plan. The rate plan in FY 2008 was revised to account for the shortfall experienced in the REPI funding and to provide a new rate scenario out to the 2030 project end date. Energy Northwest did not receive REPI funding in FY 2022 and is not anticipating receiving any future REPI incentives. The rate plan was revised In FY 2017 to reflect positive cash requirement coverage and remains in effect. Future rate adjustments may be necessary to cover the estimated costs incurred for the eventual decommissioning of the Nine Canyon Project.

## Internal Service Fund

The Internal Service Fund (ISF) (formerly the General Fund) was established in May 1957. The ISF provides services to the other funds. This fund accounts for the central procurement of certain common goods and services for the business units on a cost reimbursement basis. (See Note 1).

**Assets, Liabilities, and Net Position Analysis**

FY 2021 Total assets and deferred outflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). Total assets and deferred outflows decreased $1.5 from $38.5 million in FY 2021 to $37.0 million in FY 2022. There was an increase in net plant in service of $1.2 million, mostly related to purchases of data processing equipment. Remaining major changes were decreases to current cash and investments of $2.7 million, a $0.3 million increase in due from other business units and a $0.3 million decrease in prepayments and other current assets.

FY 2021 Total net liabilities, net position and deferred inflows have been restated for comparison purposes to include the retroactive application of GASB 87, which become effective at the beginning of FY 2022 (See Notes 1 and 13). The total net liabilities, net position and deferred inflows decreased $1.5 million. The decrease is due to a decrease in accounts payable and accrued expenses of $6.0 million offset by an increase in due to other units of $4.5 million.

**Revenues and Expenses Analysis**

Overall results of operations resulted in an increase from $4.4 million loss in FY 2021 to a $0 loss in net income for FY 2022. A contribution to the BDF was the reason for the FY 2021 loss.

## Current Debt Ratings

(Unaudited)

| Energy Northwest (Long-Term) | Net-Billed Rating | Nine Canyon Rating |
|---|---|---|
| Fitch, Inc. | AA | A |
| Moodys Investors Service, Inc. (Moodys) | Aa2 | A1 |
| Standard and Poor's Ratings Services (S & P) | AA- | NR |

## Statement of Net Position As of June 30, 2022 (Dollars in thousands)

| | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Nuclear Project No. 3 | Business Development Fund | Nine Canyon Wind Project | Subtotal | Internal Service Fund | 2022 Combined Total |
|---|---|---|---|---|---|---|---|---|---|
| **ASSETS** | | | | | | | | | |
| CURRENT ASSETS | | | | | | | | | |
| Cash | $ 60,499 | $ 1,560 | $ 3,026 | $ 3,065 | $ 5,599 | $ 8,605 | $ 82,354 | $ 8,954 | $ 91,308 |
| Investments | - | - | - | - | 4,832 | 5,940 | 10,772 | 17,247 | 28,019 |
| Accounts and other receivables | 95,781 | 136 | 7 | - | 3,380 | 59 | 99,363 | 121 | 99,484 |
| Due from other business units | - | 305 | 19 | 128 | - | 283 | 735 | (735) | - |
| Materials and supplies | 168,945 | - | - | - | - | - | 168,945 | - | 168,945 |
| Prepayments and other | 2,872 | 24 | 5 | 5 | 42 | 35 | 2,983 | 1,358 | 4,341 |
| TOTAL CURRENT ASSETS | 328,097 | 2,025 | 3,057 | 3,198 | 13,853 | 14,922 | 365,152 | 26,945 | 392,097 |
| RESTRICTED ASSETS (NOTE 1) | | | | | | | | | |
| Debt service funds | | | | | | | | | |
| Cash | 186,479 | - | 19,737 | 22,929 | - | 12,609 | 241,754 | - | 241,754 |
| Investments | 121,797 | - | - | - | - | 9,387 | 131,184 | - | 131,184 |
| Accounts and other receivables | 26 | - | - | - | - | 1 | 27 | - | 27 |
| Pension asset | 118,411 | 560 | 496 | - | 6,563 | 1,170 | 127,200 | - | 127,200 |
| TOTAL RESTRICTED ASSETS | 426,713 | 560 | 20,233 | 22,929 | 6,563 | 23,167 | 500,165 | - | 500,165 |
| NON CURRENT ASSETS | | | | | | | | | |
| UTILITY PLANT (NOTE 2) | | | | | | | | | |
| In service | 4,901,914 | 21,915 | - | - | 13,395 | 133,846 | 5,071,070 | 48,894 | 5,119,964 |
| In service - lease | 6,067 | 27 | 1,378 | - | 136 | 839 | 8,447 | 43 | 8,490 |
| Not in service | | | | | | | | | |
| Construction work in progress | 36,177 | - | - | - | - | - | 36,177 | - | 36,177 |
| Accumulated depreciation | (3,275,931) | (14,177) | - | - | (4,620) | (114,765) | (3,409,493) | (38,867) | (3,448,360) |
| Accumulated depreciation - lease | (778) | (11) | (79) | - | (6) | (32) | (906) | (39) | (945) |
| Net utility plant | 1,667,449 | 7,754 | 1,299 | - | 8,905 | 19,888 | 1,705,295 | 10,031 | 1,715,326 |
| Nuclear fuel, net of accumulated depreciation | 477,304 | - | - | - | - | - | 477,304 | - | 477,304 |
| LONG TERM RECEIVABLES | | | | | | | | | |
| Long term lease receivables | 1,976 | - | - | - | 463 | - | 2,439 | - | 2,439 |
| Other long term receivables | 1 | - | - | - | - | - | 1 | - | 1 |
| TOTAL LONG TERM RECEIVABLES | 1,977 | - | - | - | 463 | - | 2,440 | - | 2,440 |
| TOTAL NONCURRENT ASSETS | 2,146,730 | 7,754 | 1,299 | - | 9,368 | 19,888 | 2,185,039 | 10,031 | 2,195,070 |
| OTHER CHARGES | | | | | | | | | |
| Cost in excess of billings | 1,988,267 | - | 890,794 | 1,031,070 | - | - | 3,910,131 | - | 3,910,131 |
| TOTAL OTHER CHARGES | 1,988,267 | - | 890,794 | 1,031,070 | - | - | 3,910,131 | - | 3,910,131 |
| TOTAL ASSETS | 4,889,807 | 10,339 | 915,383 | 1,057,197 | 29,784 | 57,977 | 6,960,487 | 36,976 | 6,997,463 |
| DEFERRED OUTFLOWS OF RESOURCES | | | | | | | | | |
| Deferred outflows - unamortized loss on bond refunding | 3,547 | - | 2 | - | - | 608 | 4,157 | - | 4,157 |
| Deferred pension outflows | 22,740 | 107 | 95 | - | 1,260 | 226 | 24,428 | - | 24,428 |
| Deferred OPEB outflow | 1,250 | 6 | 5 | - | 69 | 13 | 1,343 | - | 1,343 |
| Deferred decommissioning outflows | 760,152 | - | - | - | 42 | 7,972 | 768,166 | - | 768,166 |
| TOTAL DEFERRED OUTFLOWS OF RESOURCES | 787,689 | 113 | 102 | - | 1,371 | 8,819 | 798,094 | - | 798,094 |
| TOTAL ASSETS AND DEFERRED OUTFLOWS | $ 5,677,496 | $ 10,452 | $ 915,485 | $ 1,057,197 | $ 31,155 | $ 66,796 | $ 7,758,581 | $ 36,976 | $ 7,795,557 |

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

## Statement of Net Position As of June 30, 2022 (Dollars in thousands)

| | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Nuclear Project No. 3 | Business Development Fund | Nine Canyon Wind Project | Subtotal | Internal Service Fund | 2022 Combined Total |
|---|---|---|---|---|---|---|---|---|---|
| **LIABILITIES AND NET POSITION** | | | | | | | | | |
| CURRENT LIABILITIES | | | | | | | | | |
| Current maturities of long-term debt | $ 102,585 | $ - | $ 395 | $ - | $ - | $ 9,755 | $ 112,735 | $ - | $ 112,735 |
| Current notes payable | 65,880 | - | - | - | - | - | 65,880 | - | 65,880 |
| Accounts payable and accrued expenses | 35,994 | 502 | 411 | 12 | 1,175 | 503 | 38,597 | 50,295 | 88,892 |
| Due to participants | 25,577 | 599 | - | - | - | - | 26,176 | - | 26,176 |
| Due to other business units | 12,540 | - | - | - | 783 | - | 13,323 | (13,323) | - |
| TOTAL CURRENT LIABILITIES | 242,576 | 1,101 | 806 | 12 | 1,958 | 10,258 | 256,711 | 36,972 | 293,683 |
| LIABILITIES-PAYABLE FROM RESTRICTED ASSETS (NOTE 1) | | | | | | | | | |
| Debt service funds | | | | | | | | | |
| Accrued interest payable | 74,115 | - | 19,717 | 23,001 | - | 1,202 | 118,035 | - | 118,035 |
| TOTAL RESTRICTED LIABILITIES | 74,115 | - | 19,717 | 23,001 | - | 1,202 | 118,035 | - | 118,035 |
| LONG-TERM DEBT (NOTE 5) | | | | | | | | | |
| Revenue bonds payable | 3,096,640 | - | 792,710 | 944,820 | - | 42,220 | 4,876,390 | - | 4,876,390 |
| Unamortized (discount)/premium on bonds - net | 402,517 | - | 76,130 | 89,174 | - | 2,572 | 570,393 | - | 570,393 |
| TOTAL LONG-TERM DEBT | 3,499,157 | - | 868,840 | 1,033,994 | - | 44,792 | 5,446,783 | - | 5,446,783 |
| OTHER LONG-TERM LIABILITIES | | | | | | | | | |
| Pension liability | 11,290 | 53 | 47 | - | 626 | 112 | 12,128 | - | 12,128 |
| OPEB Liability | 27,927 | 133 | 126 | - | 1,132 | 253 | 29,571 | - | 29,571 |
| Decommissioning liability | 1,683,441 | - | 3,961 | - | 43 | 20,676 | 1,708,121 | - | 1,708,121 |
| Long Term Lease Liability | 4,643 | 7 | 1,216 | - | 125 | 775 | 6,766 | - | 6,766 |
| Other | 96 | - | - | - | - | - | 96 | - | 96 |
| TOTAL OTHER LONG-TERM LIABILITIES | 1,727,397 | 193 | 5,350 | - | 1,926 | 21,816 | 1,756,682 | - | 1,756,682 |
| OTHER CREDITS | | | | | | | | | |
| Advances from members and others | - | 8,666 | - | - | - | - | 8,666 | - | 8,666 |
| Other | 161 | - | 155 | 155 | - | - | 471 | 4 | 475 |
| TOTAL OTHER CREDITS | 161 | 8,666 | 155 | 155 | - | - | 9,137 | 4 | 9,141 |
| TOTAL LIABILITIES | 5,543,406 | 9,960 | 894,868 | 1,057,162 | 3,884 | 78,068 | 7,587,348 | 36,976 | 7,624,324 |
| DEFERRED INFLOWS OF RESOURCES | | | | | | | | | |
| Deferred inflows - unamortized gain on bond refunding | 3,493 | - | 20,195 | 35 | - | 8 | 23,731 | - | 23,731 |
| Deferred pension inflows | 128,234 | 492 | 422 | - | 5,734 | 1,210 | 136,092 | - | 136,092 |
| Deferred lease inflow | 2,363 | - | - | - | 471 | - | 2,834 | - | 2,834 |
| TOTAL DEFERRED INFLOWS OF RESOURCES | 134,090 | 492 | 20,617 | 35 | 6,205 | 1,218 | 162,657 | - | 162,657 |
| NET POSITION | | | | | | | | | |
| Net investment in capital assets | - | - | - | - | 9,368 | (34,060) | (24,692) | 10,031 | (14,661) |
| Restricted for debt service | - | - | - | - | - | 20,796 | 20,796 | - | 20,796 |
| Restricted for pension asset | - | - | - | - | 6,563 | 1,170 | 7,733 | - | 7,733 |
| Unrestricted | - | - | - | - | 5,135 | (396) | 4,739 | (10,031) | (5,292) |
| NET POSITION | - | - | - | - | 21,066 | (12,490) | 8,576 | - | 8,576 |
| TOTAL LIABILITIES, NET POSITION, AND DEFERRED INFLOWS | $ 5,677,496 | $ 10,452 | $ 915,485 | $ 1,057,197 | $ 31,155 | $ 66,796 | $ 7,758,581 | $ 36,976 | $ 7,795,557 |

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

## Statements of Revenues, Expenses, and Changes in Net Position As of June 30, 2022 (Dollars in thousands)

| | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Nuclear Project No. 3 | Business Development Fund | Nine Canyon Wind Project | Subtotal | Internal Service Fund | 2022 Combined Total |
|---|---|---|---|---|---|---|---|---|---|
| Operating revenues | $ 425,013 | $ 2,927 | $ - | $ - | $ 14,187 | $ 17,904 | $ 460,031 | $ - | $ 460,031 |
| Lease revenues | - | - | - | - | 17 | - | 17 | - | 17 |
| OPERATING REVENUES | 425,013 | 2,927 | - | - | 14,204 | 17,904 | 460,048 | - | 460,048 |
| OPERATING EXPENSES | | | | | | | | | |
| Nuclear fuel, net | 60,270 | - | - | - | - | - | 60,270 | - | 60,270 |
| Decommissioning | 29,155 | - | - | - | 2 | 792 | 29,949 | - | 29,949 |
| Depreciation and amortization | 95,660 | 292 | - | - | 722 | 6,871 | 103,545 | - | 103,545 |
| Operations and maintenance | 194,546 | 2,812 | - | - | 12,651 | 6,202 | 216,211 | - | 216,211 |
| Administrative & general | (23,355) | (195) | - | - | (1,197) | (400) | (25,147) | - | (25,147) |
| Generation tax | 5,491 | 21 | - | - | - | 51 | 5,563 | - | 5,563 |
| Total operating expenses | 361,767 | 2,930 | - | - | 12,178 | 13,516 | 390,391 | - | 390,391 |
| OPERATING INCOME (LOSS) | 63,246 | (3) | - | - | 2,026 | 4,388 | 69,657 | - | 69,657 |
| OTHER INCOME & EXPENSE | | | | | | | | | |
| Other | 28,452 | - | 23,201 | 26,687 | - | - | 78,340 | - | 78,340 |
| Other lease revenue | 600 | - | - | - | - | - | 600 | - | 600 |
| Grant revenue non operating | - | - | - | - | 62 | - | 62 | - | 62 |
| Gain on DOE settlement | 21,137 | - | - | - | - | - | 21,137 | - | 21,137 |
| Investment income/(loss) | (87) | 4 | 13 | 12 | (110) | (390) | (558) | - | (558) |
| Interest expense and debt amortization | (113,359) | (1) | (20,835) | (26,407) | (3) | (1,751) | (162,356) | - | (162,356) |
| Plant preservation and termination costs | - | - | (381) | (292) | - | - | (673) | - | (673) |
| Depreciation and amortization | - | - | (82) | - | - | - | (82) | - | (82) |
| Decommissioning | - | - | (1,916) | - | - | - | (1,916) | - | (1,916) |
| TOTAL OTHER INCOME & EXPENSE | (63,257) | 3 | - | - | (51) | (2,141) | (65,446) | - | (65,446) |
| NET INCOME (LOSS) BEFORE CONTRIBUTIONS | (11) | - | - | - | 1,975 | 2,247 | 4,211 | - | 4,211 |
| CAPITAL CONTRIBUTIONS | 11 | - | - | - | 149 | - | 160 | - | 160 |
| NET INCOME (LOSS) AFTER CON-TRIBUTIONS | - | - | - | - | 2,124 | 2,247 | 4,371 | - | 4,371 |
| TOTAL NET POSITION AS RESTATED, BEGINNING OF YEAR * | - | - | - | - | 18,942 | (14,737) | 4,205 | - | 4,205 |
| TOTAL NET POSITION, END OF YEAR | $ - | $ - | $ - | $ - | $ 21,066 | $ (12,490) | $ 8,576 | $ - | $ 8,576 |

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

* Energy Northwest's 2021 Statement of Net Position and Statements of Revenues and Expenses and Changes in Net Position were updated for the impacts of the required retroactive application of GASB 87 "Lease Accounting" which became effective for Energy Northwest in fiscal year 2022. See Note 1 for a summary of this change in accounting principle.

## Statements of Cash Flows As of June 30, 2022 (Dollars in thousands)

| | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Nuclear Project No. 3 | Business Development Fund | Nine Canyon Wind Project | Internal Service Fund | 2022 Combined Total |
|---|---|---|---|---|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | | | | | | |
| Operating revenue receipts | $ 400,440 | $ 3,363 | $ - | $ - | $ 9,149 | $ 18,007 | $ - | $ 430,959 |
| Cash payments for operating expenses | (267,627) | (2,849) | - | - | (9,687) | (6,330) | - | (286,493) |
| Cash received from TVA fuel activities | 86,020 | - | - | - | - | - | - | 86,020 |
| Cash payments for services net of cash received from other units | - | - | - | - | - | - | (1,877) | (1,877) |
| Net cash provided/(used) by operating activities | 218,833 | 514 | - | - | (538) | 11,677 | (1,877) | 228,609 |
| CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES | | | | | | | | |
| Proceeds from bond refundings | 174,131 | - | 21,154 | 21,005 | - | - | - | 216,290 |
| Principal paid on revenue bond maturities | (102,225) | - | - | (2,380) | - | (9,295) | - | (113,900) |
| Payment for bond issuance and financing costs | (3,206) | (11) | (885) | (403) | (30) | (33) | - | (4,568) |
| Interest paid on bonds | (147,450) | - | (38,941) | (45,621) | - | (2,629) | - | (234,641) |
| Interest paid on leases | (143) | (1) | (33) | - | (3) | (20) | - | (200) |
| Payment for capital items | (109,059) | (646) | - | - | (862) | - | (3,405) | (113,972) |
| Reimbursement for capital items | - | - | - | - | - | - | 3,238 | 3,238 |
| Capital grant received | 443 | - | - | - | 667 | - | - | 1,110 |
| Operating revenue receipts - lease | - | - | - | - | 24 | - | - | 24 |
| Non operating revenue receipts - lease | 643 | - | - | - | - | - | - | 643 |
| Nuclear fuel acquisitions | (37,169) | - | - | - | - | - | - | (37,169) |
| Payments received from BPA for terminated nuclear projects | - | - | 19,325 | 25,386 | - | - | - | 44,711 |
| Net cash provided/(used) by capital and related financing activities | (224,035) | (658) | 620 | (2,013) | (204) | (11,977) | (167) | (238,434) |
| CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES | | | | | | | | |
| Proceeds from notes payable | 94,431 | - | 10,375 | 10,458 | - | - | - | 115,264 |
| Payment for notes payable | (114,471) | - | (10,375) | (10,458) | - | - | - | (135,304) |
| Interest paid on notes | (302) | - | (45) | (45) | - | - | - | (392) |
| Grant received non operating | - | - | - | - | 35 | - | - | 35 |
| Net cash provided/(used) by non-capital finance activities | (20,342) | - | (45) | (45) | 35 | - | - | (20,397) |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | | | | | | |
| Purchases of investment securities | (362,870) | - | (13,048) | (15,113) | (7,000) | (21,367) | (10,782) | (430,180) |
| Sales of investment securities | 346,505 | - | 13,051 | 15,117 | 5,901 | 18,283 | 12,055 | 410,912 |
| Interest on investments | 1,211 | 3 | 10 | 8 | 91 | 305 | 307 | 1,935 |
| Net cash provided/(used) by investing activities | (15,154) | 3 | 13 | 12 | (1,008) | (2,779) | 1,580 | (17,333) |
| NET INCREASE(DECREASE) IN CASH | (40,698) | (141) | 588 | (2,046) | (1,715) | (3,079) | (464) | (47,555) |
| CASH AT JUNE 30, 2021 | 287,676 | 1,701 | 22,175 | 28,040 | 7,314 | 24,293 | 9,418 | 380,617 |
| CASH AT JUNE 30, 2022 (NOTE H) | $ 246,978 | $ 1,560 | $ 22,763 | $ 25,994 | $ 5,599 | $ 21,214 | $ 8,954 | $ 333,062 |

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

## Statements of Cash Flows As of June 30, 2022 (Dollars in thousands)

| | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Nuclear Project No. 3 | Business Development Fund | Nine Canyon Wind Project | Internal Service Fund | 2022 Combined Total |
|---|---|---|---|---|---|---|---|---|
| Reconciliation of Direct Cash Flow to Statement of Net Position | | | | | | | | |
| Cash unrestricted | $ 60,499 | $ 1,560 | $ 3,026 | $ 3,065 | $ 5,599 | $ 8,605 | $ 8,954 | $ 91,308 |
| Cash restricted special funds | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cash restricted debt service funds | $ 186,479 | $ - | $ 19,737 | $ 22,929 | $ - | $ 12,609 | $ - | $ 241,754 |
| Total Statement of Net Position cash | $ 246,978 | $ 1,560 | $ 22,763 | $ 25,994 | $ 5,599 | $ 21,214 | $ 8,954 | $ 333,062 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES | | | | | | | | |
| Net income/loss from operations | $ 63,246 | $ (3) | $ - | $ - | $ 2,026 | $ 4,388 | $ - | $ 69,657 |
| Adjustments to reconcile net operating revenues to cash provided by operating activities: | | | | | | | | |
| Depreciation and amortization | 149,604 | 292 | - | - | 722 | 6,871 | - | 157,489 |
| Decommissioning | 29,155 | - | - | - | 2 | 792 | - | 29,949 |
| Non-operating Grant Revenues | - | - | - | - | (62) | - | - | (62) |
| Other | 37,753 | 64 | - | - | 363 | 219 | (72) | 38,327 |
| Change in operating assets and liabilities: | | | | | | | | |
| Costs in excess of billings | 27,937 | 393 | - | - | - | - | - | 28,330 |
| Accounts receivable | (2,210) | 44 | - | - | (1,045) | (187) | (375) | (3,773) |
| Materials and supplies | (1,388) | - | - | - | - | - | - | (1,388) |
| Prepaid and other assets | (112) | 1 | - | - | (17) | (1) | 339 | 210 |
| Due from/to other business units | (4,804) | (248) | - | - | 288 | 81 | 4,207 | (476) |
| Change in net pension liability, OPEB Liability, and deferrals | (35,660) | (186) | - | - | (2,136) | 372 | (3) | (37,613) |
| Leases | (5,789) | (16) | - | - | (152) | (787) | - | (6,744) |
| Accounts payable | (38,899) | 173 | - | - | (527) | (71) | (5,973) | (45,297) |
| Net cash provided/(used) by operating activities | $ 218,833 | $ 514 | $ - | $ - | $ (538) | $ 11,677 | $ (1,877) | $ 228,609 |
| Non-cash activities | | | | | | | | |
| Capitalized interest | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Bond refunding | $ 279,668 | $ - | $ 90,171 | $ 105 | $ - | $ - | $ - | $ 369,944 |
| Decommissioning liability adjustment | $ 133,311 | $ - | $ - | $ - | $ 3 | $ 1,637 | $ - | $ 134,951 |
| Excise tax on nuclear fuel acquisitions | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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

## Notes To Financial Statements

**NOTE 1 - Summary of Operations and Significant Accounting Policies**

Energy Northwest, a municipal corporation and joint operating agency of the state of Washington, was organized in 1957 to finance, acquire, construct and operate facilities for the generation and transmission of electric power.

Membership consists of 22 public utility districts and 5 municipalities. All members own and operate electric systems within the state of Washington.

Energy Northwest is exempt from federal income tax and has no taxing authority.

Energy Northwest maintains seven business units. Each unit is financed and accounted for separately from all other current or future business units and is accounted for as a major fund for governmental accounting purposes.

All electrical energy produced by Energy Northwest's net-billed business units is ultimately delivered to electrical distribution facilities owned and operated by Bonneville Power Administration (BPA) as part of the Federal Columbia River Power System. BPA in turn distributes the electricity to electric utility systems throughout the Northwest, including participants in Energy Northwest's business units, for ultimate distribution to consumers. Participants in Energy Northwest's net-billed business units consist of public utilities and rural electric cooperatives located in the western United States who have entered into net-billing agreements with Energy Northwest and BPA for participation in one or more of Energy Northwest's business units. BPA is obligated by law to establish rates for electric power which will recover the cost of electric energy acquired from Energy Northwest and other sources, as well as BPA's other costs (See Note 5).

Energy Northwest operates the Columbia Generating Station (Columbia), a 1,174-MWe (Design Electric Rating, net) generating plant completed in 1984. Energy Northwest has obtained all permits and licenses required to operate Columbia. Columbia was issued a standard 40-year operating license by the Nuclear Regulatory Commission (NRC) in 1983. On January 19, 2010 Energy Northwest submitted an application to the NRC to renew the license for an additional 20 years, thus continuing operations to 2043. A renewal license was granted by the NRC on May 22, 2012 for continued operation of Columbia to December 31, 2043.

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5-MWe generating plant completed in 1964. Packwood has been operating under a 50-year license issued by the Federal Energy Regulatory Commission (FERC), which expired on February 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on February 22, 2008. On October 11, 2018, FERC issued forty-year operating license effective October 1, 2018.

The electric power produced by Packwood is sold to 12 project participant utilities which pay the costs of Packwood. The Packwood participants are obligated to pay annual costs of Packwood including debt service, whether or not Packwood is operable. The participants also share Packwood revenue (See Note 5).

Nuclear Project No. 1, a 1,250-MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. Nuclear Project No. 3, a 1,240-MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. All funding requirements remain as net-billed obligations of Nuclear Projects Nos. 1 and 3. Energy Northwest is no longer responsible for site restoration costs for Nuclear Project No. 3. (See Note 10)

The Business Development Fund was established in April 1997 to pursue and develop new energy related business opportunities. There are five main business lines associated with this business unit: Business Support, Energy & Professional Services, Laboratory Support, Nuclear Development, and Operations & Maintenance Services.

The Nine Canyon Wind Project (Nine Canyon) was established in January 2001 for the purpose of exploring and establishing a wind energy project. Phase I of the project was completed in FY 2003 and Phase II was completed in FY 2004. Phase I and II combined capacity is approximately 63.7 MWe. Phase III was completed in FY 2008 adding an additional 14 wind turbines to Nine Canyon and adding an aggregate capacity of 32.2 MWe. The total number of turbines at Nine Canyon is 63 and the total capacity is 95.9 MWe.

The Internal Service Fund was established in May 1957. It is currently used to account for the central procurement of certain common goods and services for the business units on a cost reimbursement basis.

Energy Northwest's fiscal year (FY) begins on July 1 and ends on June 30.

The following is a summary of the significant accounting policies:

**A) Basis of Accounting and Presentation:** The accounting policies of Energy Northwest conform to Generally Accepted Accounting Principles (GAAP) applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles this includes all GASB implementation guides, GASB technical Bulletins, and guidance from the American Institute of Certified

Public Accountants (AICPA) that is cleared by GASB. The accounting and reporting policies of Energy Northwest are regulated by the Washington State Auditor's Office and are based on the Uniform System of Accounts prescribed for public utilities and licensees by FERC. Energy Northwest uses an accrual basis of accounting where revenues are recognized when earned and expenses are recognized when incurred. Revenues and expenses related to Energy Northwest's operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be other income and expenses. Separate funds and books of accounts are maintained for each business unit. Payment of the obligations of one business unit with funds of another business unit is prohibited and would constitute violation of bond resolution covenants (See Note 4).

Energy Northwest maintains an Internal Service Fund for centralized control and accounting of certain capital assets such as data processing equipment, and for payment and accounting of internal services, payroll, benefits, administrative and general expenses, and certain contracted services on a cost reimbursement basis. Certain assets in the Internal Service Fund are also owned by this Fund and operated for the benefit of other projects. Depreciation relating to capital assets is charged to the appropriate business units based upon assets held by each project.

Liabilities of the Internal Service Fund represent accrued payroll, vacation pay, employee benefits, such as pensions and other post-retirement benefits, and common accounts payable which have been charged directly or indirectly to business units and will be funded by the business units when paid. Net amounts owed to, or from, Energy Northwest business units are recorded as Current Liabilities–Due to other business units, or as Current Assets–Due from other business units on the Internal Service Fund Statement of Net Position.

The combined total column on the financial statements is for presentation only as each Energy Northwest business unit is financed and accounted for separately from all other current and future business units. The Combined Total includes eliminations for transactions between business units as required in GASB Statement No. 34, "Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments".

**Issued but not Adopted Guidance:**

GASB Statement No. 94, "Public-Private and Public-Public Partnerships and Availability Payment Arrangements." The primary objective of this Statement is to improve financial reporting by addressing issues related to public-private and public-public partnership arrangements and related payments providing guidance for those transactions. This statement is effective for Energy Northwest in fiscal year 2023. Energy Northwest is currently evaluating the full impact of this statement.

GASB Statement No. 96, "Subscription-Based Information Technology Arrangements." This Statement provides guidance on the accounting and financial reporting for subscription-based information technology arrangements (SBITAs) for government end users (governments). This Statement (1) defines a SBITA; (2) establishes that a SBITA results in a right-to-use subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. To the extent relevant, the standards for SBITAs are based on the standards established in Statement No. 87, Leases, as amended. This statement is effective for Energy Northwest in fiscal year 2023. Energy Northwest is currently evaluating the full impact of this statement and will implement in FY2023.

GASB Statement No. 100, Accounting Changes and Error Corrections—an amendment of GASB Statement No. 62. The primary objective of this Statement is to enhance accounting and financial reporting requirements for accounting changes and error corrections to provide more understandable, reliable, relevant, consistent, and comparable information for making decisions or assessing accountability. This statement is effective for Energy Northwest in fiscal year 2024. Energy Northwest is currently evaluating this statement.

GASB Statement No. 101, Compensated Absences. The objective of this Statement is to better meet the information needs of financial statement users by updating the recognition and measurement guidance for compensated absences. That objective is achieved by aligning the recognition and measurement guidance under a unified model and by amending certain previously required disclosures. This statement is effective for Energy Northwest in fiscal year 2024. Energy Northwest is currently evaluating the impact of the statement.

**Change in Accounting Principle**

In fiscal year 2022, Energy Northwest implemented GASB Statement No. 87 Leases. GASB Statement No. 87 addresses accounting and financial reporting for leases. This Statement increases the usefulness of governments' financial statements by requiring recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and recognized as inflows of resources or outflows of resources based on the payment provisions of the contract. Note disclosure and required supplementary information requirements about leases also are addressed. The restatement of lease related balances is outlined in the table below. See financial statement Note 13 for further details on the impact to Energy Northwest.

| (Dollars in Thousands) | Columbia Generating Station | Packwood Lake Hydroelectric Project | Nuclear Project No. 1 | Business Development Fund | Nine Canyon Wind Project | Internal Service Fund |
|---|---|---|---|---|---|---|
| **7/1/21 Balances Previously Reported** | | | | | | |
| Deferred Inflow - Leases | $ - | $ - | $ - | $ - | $ - | $ - |
| Lease Liabilty | - | - | - | - | - | - |
| Lease Asset | - | - | - | - | - | - |
| Lease Receivable | - | - | - | - | - | - |
| **7/1/21 Restated Balance** | | | | | | |
| Deferred Inflow - Leases | $ (4,325) | $ - | $ - | $ (488) | $ - | $ - |
| Lease Liabilty | (6,067) | (27) | (1,378) | (136) | (839) | (43) |
| Lease Asset | 6,067 | 27 | 1,378 | 136 | 839 | 43 |
| Lease Receivable | 4,325 | - | - | 488 | - | - |
| **Changes in Current Year** | | | | | | |
| Deferred Inflow - Leases | $ 1,962 | $ - | $ - | $ 17 | $ - | $ - |
| Lease Liabilty | 685 | 11 | 96 | 7 | 42 | 39 |
| Lease Asset | (778) | (11) | (79) | (6) | (32) | (39) |
| Lease Receivable | (1,928) | - | - | (12) | - | - |
| **6/30/22 Balances** | | | | | | |
| Deferred Inflow - Leases | $ (2,363) | $ - | $ - | $ (471) | $ - | $ - |
| Lease Liabilty | (5,382) | (16) | (1,282) | (129) | (797) | (4) |
| Lease Asset | 5,289 | 16 | 1,299 | 130 | 807 | 4 |
| Lease Receivable | 2,397 | - | - | 476 | - | - |

**B) Utility Plant and Depreciation:** Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs.

Property, plant, and equipment are depreciated using the straight-line method over the following estimated useful lives:

| | |
|---|---|
| Buildings and Improvements | 20 - 60 years |
| Generation Plant | 40 years |
| Transportation Equipment | 6 - 10 years |
| General Plant and Equipment | 5 - 15 years |

Group rates are used for assets and, accordingly, no gain or loss is recorded on the disposition of an asset unless it represents a major retirement. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation.

The utility plant and net position of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in FY 1995 and included in Cost in Excess of Billings. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 1 and 3 have been charged to other income and expense (See Note 10).

Projects are generally capitalized if they are over $50 thousand and meet the improvement or extension criteria set forth in Energy Northwest's capitalization policy.

**C) Capital Contributions:** Energy Northwest (EN) is involved in various grants. We received $11 thousand in fiscal year 2022 related to a federal award for Advanced Remote Monitoring at Columbia. Business Development received $140 thousand in fiscal year 2022 related to vehicle electrification through a Washington State Department of Commerce. Through a private grant related to coal transition for vehicle electrification stations Business Development also received $9 thousand. Energy Northwest recently received a subrecipient award from a federal grant for the Advanced Reactor Demonstration Program, no monies had been received on June 30. The primary recipient is Terra Power.

**D) Nuclear Fuel:** Energy Northwest has various agreements for uranium concentrates, conversion, and enrichment to provide for short-term enriched uranium product and long-term enrichment services. All expenditures related to the initial purchase of nuclear fuel for Columbia are carried at cost.

**E) Decommissioning Liability:** Energy Northwest has adopted GASB Statement No. 83 "Certain Asset Retirement Obligations". GASB No. 83 addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. Legal obligations exist for Energy Northwest to perform future asset retirement activities related to certain tangible assets. Accordingly, GASB No. 83 requires recognizing a liability for this obligation. (See Note 9)

**F) Decommissioning and Site Restoration:** Energy Northwest established decommissioning and site restoration funds for Columbia and monies are being deposited each year in accordance with an established funding plan (See Note 9).

**G) Restricted Assets:** In accordance with bond resolutions, related agreements and laws, separate restricted accounts have been established. These assets are restricted for specific uses including debt service, construction, capital additions and fuel purchases. When both restricted and unrestricted resources are available for use, it is Energy Northwest's policy to use restricted resources first, then unrestricted resources as they are needed.

**H) Cash and Investments:** For purposes of the Statement of Cash Flows, cash includes unrestricted and restricted cash balances, and each business unit maintains its cash and investments. Short-term highly liquid investments are not considered to be cash equivalents; and are stated at fair value with unrealized gains and losses reported in investment income (See Note 3). Energy Northwest resolutions and investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association and Federal Home Loan Banks. Safe keeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest business units.

**I) Accounts Receivable:** The percentage of sales method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a yearly basis. Accounts receivable specific to each business unit are recorded in the residing business unit. In FY 2022 the evaluation of current accounts receivable resulted in no allowance for uncollectible accounts being recorded. The total balance for uncollectible receivables is zero.

**J) Other Receivables:** Other receivables include amounts related to the Internal Service Fund from miscellaneous outstanding receivables from other business units which have not yet been collected. The amounts due to each business unit are reflected in Due To/From other business units. Other receivables specific to each business unit are recorded in the residing business unit. No allowances were deemed necessary at the end of the fiscal year. Payments made by members in advance of expenses incurred are included as advances from members in the Statement of Net Position.

**K) Materials and Supplies:** Materials and supplies are valued at cost using the weighted average cost method.

**L) Leases:** For long-term leases as of July 1, 2021, that have a present value of future payments over a certain dollar value for each business unit, which do not transfer ownership of the underlying asset, and EN is the lessee, a lease liability, and a lease asset have been established in accordance with GASB Statement No. 87 (See Note 13). To be included the present value of future payments need to be for Columbia leases of $100 thousand or greater, for Business Development Fund leases of $5 thousand or greater, for Internal Service Fund leases of $25 thousand or greater, for Unit 1 leases of $50 thousand or greater, for Nine Canyon leases of $5 thousand or greater, and for Packwood leases of $5 thousand or greater. The lease liability was established at the present value of payments expected to be made during the lease term (less any lease incentives). The lease asset was established at the amount of the initial measurement of the lease liability, plus any payments made to the lessor at or before the commencement of the lease term and certain direct costs.

For long term leases as of July 1, 2021, that have a present value of future receipts over a certain dollar value for each business unit, which EN is the lessor, a lease receivable and a deferred inflow of resources have been established in accordance with GASB Statement No. 87 (See Note 13). To be included the present value of future receipts need to be for Columbia leases of $100 thousand or greater, for Business Development Fund leases of $5 thousand or greater, for Internal Service Fund leases of $25 thousand or greater, for Unit 1 leases of $50 thousand or greater, for Nine Canyon leases of $5 thousand or greater, and for Packwood leases of $5 thousand or greater. The lease receivable was established at the present value of lease payments expected to be received during the lease term. The deferred inflow of resources was established at the value of the lease receivable plus any payments received at or before the commencement of the lease term that relate to future periods.

**M) Long-Term Liabilities:** Consist of obligations related to bonds payable and the associated premiums/discounts and gains/losses. Other noncurrent liabilities are pension liabilities recognized according to GASB Statement No. 68 (See Note 6), asset retirement obligations (See Note 9), OPEB liabilities (See Note 12) and other immaterial liabilities. The table below summarizes activities for all long-term liabilities excluding pension and decommissioning liabilities.

## Long-Term Liabilities (Dollars in thousands)

| | | Balance 6/30/2021 | | Increase | | Decrease | | Balance 6/30/2022 |
|---|---|---|---|---|---|---|---|---|
| **Columbia Generating Station** | | | | | | | | |
| Revenue bonds payable | $ | 3,078,800 | $ | 397,835 | $ | 379,995 | $ | 3,096,640 |
| Unamortized (discount)/premium on bonds - net | | 386,034 | | 53,706 | | 37,223 | | 402,517 |
| Current maturities of long-term debt | | 102,225 | | 102,585 | | 102,225 | | 102,585 |
| Other noncurrent liabilities | | 92 | | 4 | | - | | 96 |
| | $ | 3,567,151 | $ | 554,130 | $ | 519,443 | $ | 3,601,838 |
| **Nuclear Project No.1** | | | | | | | | |
| Revenue bonds payable | $ | 782,945 | $ | 99,775 | $ | 90,010 | $ | 792,710 |
| Unamortized (discount)/premium on bonds - net | | 90,567 | | 10,993 | | 25,430 | | 76,130 |
| Current maturities of long-term debt | | - | | 395 | | - | | 395 |
| | $ | 873,512 | $ | 111,163 | $ | 115,440 | $ | 869,235 |
| **Nuclear Project No.3** | | | | | | | | |
| Revenue bonds payable | $ | 926,260 | $ | 18,560 | $ | - | $ | 944,820 |
| Unamortized (discount)/premium on bonds - net | | 106,392 | | 2,448 | | 19,666 | | 89,174 |
| Current maturities of long-term debt | | 2,380 | | - | | 2,380 | | - |
| | $ | 1,035,032 | $ | 21,008 | $ | 22,046 | $ | 1,033,994 |
| **Nine Canyon Wind Project** | | | | | | | | |
| Revenue bonds payable | $ | 51,975 | $ | - | $ | 9,755 | $ | 42,220 |
| Unamortized (discount)/premium on bonds - net | | 3,392 | | - | | 820 | | 2,572 |
| Current maturities of long-term debt | | 9,295 | | 9,755 | | 9,295 | | 9,755 |
| | $ | 64,662 | $ | 9,755 | $ | 19,870 | $ | 54,547 |
| **Business Development Fund** | | | | | | | | |
| Other noncurrent liabilities | | 16 | | - | | 16 | | - |
| | $ | 16 | $ | - | $ | 16 | $ | - |
| **Internal Service Fund** | | | | | | | | |
| Other noncurrent liabilities | | 3 | | - | | (1) | | 4 |
| | $ | 3 | $ | - | $ | (1) | $ | 4 |

**N) Debt Premium, Discount and Expense:** Original issue and reacquired bond premiums, discounts relating to the bonds are amortized over the terms of the respective bond issues using the bonds outstanding method which approximates the effective interest method. In accordance with GASB Statement No. 65, "Items Previously Reported as Assets and Liabilities", gains and losses on debt refundings have been deferred and amortized as a component of interest expense over the shorter of the remaining life of the old or new debt. Expenses related to debt issuance are expensed as incurred.

Senior Lien Bonds (Bearer Bonds) were issued for Project 1, Columbia, Project 3, and Packwood. At the time of issuance there were no registration requirements on the bonds. While the amount of the bearer bonds outstanding is unknown, Energy Northwest recognizes there is a contingency related to this debt that may be redeemed in the future. An estimated amount of cash required for the unpresented bonds was calculated and the Energy Northwest Custodial Account Tracking is done by US Bank. The bank holds an estimate of cash required to pay claims on these bonds. Once the bond has matured the cash is released to Energy Northwest. Once identified by the bank the designated maturity requirements have been met, the cash is provided to Energy Northwest. These escheated funds are then returned to Bonneville Power Administration. Energy Northwest maintains a $500 thousand liability on the balance sheet for the unclaimed bearer bonds and related cash to pay for claims as necessary and annually replenishes the funds through a contract with Bonneville Power Administration.

**O) Revenue and Expenses:** Energy Northwest accounts for expenses and revenues on an accrual basis, and recovers, through various agreements, actual cash requirements for operations and debt service for Columbia, Packwood, Nuclear Project No. 1 and Nuclear Project No. 3. For these business units, Energy Northwest recognizes revenues equal to expenses for each period. Revenues of Nuclear Project No.1 and Nuclear Project No.3 are recorded under other income and expense, as these two business units are terminated nuclear projects. No net revenue or loss is recognized, and no net position is accumulated. The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (other credits) or as costs in excess of billings (other charges), as appropriate. Such amounts will be settled during future operating periods (See Note 5).

The difference between cumulative revenues and cumulative expenses for Packwood Hydroelectric, Nine Canyon and Business Development is recognized as net income or loss and included in Net Position for each period.

Energy Northwest distinguishes operating revenues and expenses from other income and expense items. Operating revenues and expenses generally result from the Net Billing agreements stated above or from services provided by EN's principal operations. Operating expenses for Energy Northwest include the costs of operating the generation producing facility, related administrative fees, and depreciation on utility plant. All revenues and expenses not meeting this definition are reported as other income or expense.

**P) Compensated Absences:** Employees earn leave in accordance with length of service. Energy Northwest accrues the cost of personal leave in the year when earned. The liability for unpaid leave benefits and related payroll taxes was $26 million at the end of this fiscal year and is recorded as a current liability.

**Q) Use of Estimates:** The preparation of Energy Northwest financial statements in conformity with GAAP requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Certain incurred expenses and revenues are allocated to the business units based on specific allocation methods that management considers to be reasonable.

**R) Deferred Inflows and Outflows:** Deferred outflows of resources are defined as the consumption of net assets by Energy Northwest that are applicable to a future reporting period and are reported in the statement of financial position in a separate section following assets. Deferred inflows of resources are defined as acquisitions of net assets by Energy Northwest that is applicable to a future reporting period and are reported in the statement of financial position in a separate section following liabilities.

These amounts consist of losses and gains on bond refundings, subsequent contributions, difference between projected and actual investment income, decommissioning costs (See Note 9), OPEB cost (See Note 12), lease cost (See note 13) and other pension related costs (See Note 6) as labeled on the Statement of Net Position.

**S) Short-Term Debt:** A revolving loan agreement, Electric Revenue Bond Anticipation Note 2020A/B, was amended on April 30, 2021 to fund operations and maintenance expense and debt service for Columbia as well as a portion of debt service for Project 1 and Project 3. The 2020A/B Note agreement is not to exceed $110 million with a final maturity of April 30, 2024. As of June 30, 2022, $65.8 million was borrowed for Columbia. These balances are included in current notes payable in the Statement of Net Position.

No assets were directly pledged as collateral for the above-mentioned loan agreement. The loan agreement is supported by the Net Billing Agreements with the Bonneville Power Administration and the Project Participants. The 2020A/B Note is secured by revenues of the Columbia Generating Station; no assets secure the Notes. A portion of the Electric Revenue Bond Anticipation Note, 2020A/B is secured by revenues of Project 1 and Project 3. The covenants include covenants to (1) comply with laws and relevant resolutions, (2) maintain the facilities comprising and obtain insurance on Columbia, (3) collect sufficient rates and charges to repay the Notes and all other obligations of Columbia, and (4) not to rescind or amend the project related documents or authorizing documents in any material way. Events of default include failure to repay the Notes or any Columbia, Project 1, or Project 3 bonds when due, any representation is materially incorrect, covenant defaults, invalidity, insolvency, and a judgment in excess of $15 million that is not satisfied or appealed. Remedies upon an event of default include (1) the Notes will bear interest at a default rate, (2) acceleration, but only if the Parity Bonds have been accelerated and such acceleration does not violate state law or the Columbia, Project 1, or Project 3 bond resolutions, and revenues will be turned over to the trustee for the Columbia, Project 1, or Project 3 bonds.

**T) Pensions:** For purposes of measuring the net pension liability (asset), deferred outflows of resources and deferred inflows of resources related to pensions, and pension expense, information about the fiduciary net position of the Washington State Public Employees Retirement System (PERS) and additions to/deductions from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms, investments are reported at fair value.

**U) OPEB:** For purposes of measuring the net OPEB liability, deferred outflows of resources and deferred inflows of resources related to OPEB related to the implicit benefit of receiving medical through PERS have been recorded. Energy Northwest does not directly contribute to any post-employment benefit related to medical insurance.

## Short-term Liabilities (Dollars in thousands)

| | Balance Outstanding at 6/30/2021 | Increases | Decreases | Balance Outstanding 6/30/2022 |
|---|---|---|---|---|
| **Columbia Generating Station** | | | | |
| Non-Revolving Loan | $ 85,920 | $ 94,431 | $ 114,471 | $ 65,880 |
| **Nuclear Project No.1** | | | | |
| Non-Revolving Loan | $ - | $ 10,375 | $ 10,375 | $ - |
| **Nuclear Project No.3** | | | | |
| Non-Revolving Loan | $ - | $ 10,458 | $ 10,458 | $ - |
| **Nine Canyon Wind Project** | | | | |
| Short-term debt | - | - | - | - |
| **Packwood Lake Hydroelectric Project** | | | | |
| Short-term debt | - | - | - | - |
| **Business Development Fund** | | | | |
| Short-term debt | - | - | - | - |
| Total | $ 85,920 | $ 115,264 | $ 135,304 | $ 65,880 |

## NOTE 2 - Utility Plant

Utility plant activity for the year ended June 30, 2022 was as follows:

| | | Balance 06/30/2021 | | Capital Acquisitions | | Sale or Other Dispositions | | Balance 06/30/2022 |
|---|---|---|---|---|---|---|---|---|
| **Columbia Generating Station** | | | | | | | | |
| Generation | $ | 4,730,961 | $ | 126,593 | $ | (70) | $ | 4,857,484 |
| Intangible Right-To-Use Lease Asset | | 6,067 | | - | | - | | 6,067 |
| Intangible Plant | | 39,265 | | 5,165 | | - | | 44,430 |
| Construction Work in Progress | | 68,046 | | 105,229 | | (137,099) | | 36,176 |
| Accumulated Depreciation | | (3,183,377) | | (92,624) | | 70 | | (3,275,931) |
| Accumulated Depreciation Intangible Right-To-Use Lease Asset | | - | | (778) | | - | | (778) |
| Utility Plant net* | $ | 1,660,962 | $ | 143,585 | $ | (137,099) | $ | 1,667,449 |
| **Packwood Lake Hydroelectric Project** | | | | | | | | |
| Generation | $ | 17,610 | $ | 568 | $ | - | $ | 18,178 |
| Intangible Right-To-Use Lease Asset | | 27 | | - | | - | | 27 |
| Intangible Plant | | 3,737 | | - | | - | | 3,737 |
| Construction Work in Progress | | - | | - | | - | | - |
| Accumulated Depreciation | | (13,909) | | (268) | | - | | (14,177) |
| Accumulated Depreciation Intangible Right-To-Use Lease Asset | | - | | (11) | | - | | (11) |
| Utility Plant net | $ | 7,465 | $ | 289 | $ | - | $ | 7,754 |
| **Business Development Fund** | | | | | | | | |
| Generation | $ | 12,654 | $ | 741 | $ | - | $ | 13,395 |
| Intangible Right-To-Use Lease Asset | | 136 | | - | | - | | 136 |
| Construction Work in Progress | | - | | - | | - | | - |
| Accumulated Depreciation | | (3,918) | | (702) | | - | | (4,620) |
| Accumulated Depreciation Intangible Right-To-Use Lease Asset | | - | | (6) | | - | | (6) |
| Utility Plant net | $ | 8,736 | $ | 169 | $ | - | $ | 8,905 |
| **Nine Canyon Wind Project** | | | | | | | | |
| Generation | $ | 133,846 | $ | - | $ | - | $ | 133,846 |
| Intangible Right-To-Use Lease Asset | | 839 | | - | | - | | 839 |
| Construction Work in Progress | | - | | - | | - | | - |
| Accumulated Depreciation | | (107,957) | | (6,808) | | - | | (114,765) |
| Accumulated Depreciation Intangible Right-To-Use Lease Asset | | - | | (32) | | - | | (32) |
| Utility Plant, net* | $ | 26,728 | $ | (6,840) | $ | - | $ | 19,888 |
| **Internal Service Fund** | | | | | | | | |
| Generation | $ | 45,914 | $ | 3,477 | $ | (497) | $ | 48,894 |
| Intangible Right-To-Use Lease Asset | | 43 | | - | | - | | 43 |
| Construction Work in Progress | | - | | - | | - | | - |
| Accumulated Depreciation | | (37,080) | | (2,284) | | 497 | | (38,867) |
| Accumulated Depreciation Capital Leases | | - | | (39) | | - | | (39) |
| Utility Plant net | $ | 8,877 | $ | 1,154 | $ | - | $ | 10,031 |
| **Nuclear Project No.1** | | | | | | | | |
| Intangible Right-To-Use Lease Asset | $ | 1,378 | $ | - | $ | - | $ | 1,378 |
| Construction Work in Progress | | - | | - | | - | | - |
| Accumulated Depreciation Intangible Right-To-Use Lease Asset | | - | | (79) | | - | | (79) |
| Lease Plant net | $ | 1,378 | $ | (79) | $ | - | $ | 1,299 |

* Does not include nuclear fuel, net of amortization

**NOTE 3 - Investments**

**Interest rate risk:** In accordance with its investment policy, Energy Northwest manages its exposure to declines in fair values by limiting investments to those with maturities as designated in specific bond resolutions to coincide with expected use of the funds.

**Credit risk:** Energy Northwest's investment policy restricts investments to debt securities and obligations of the U.S. Treasury, U.S. government agencies Federal National Mortgage Association and the Federal Home Loan Banks, certificates of deposit and other evidences of deposit at financial institutions qualified by the Washington Public Deposit Protection Commission (PDPC), and general obligation debt of state and local governments and public authorities recognized with one of the three highest credit ratings (AAA, AA+, AA, or equivalent). This investment policy is more restrictive than the state law.

**Concentration of credit risk:** Energy Northwest's investment policy has restrictions on concentration of credit risk. No limits of concentration are set on U.S. Treasury related to securities or cash holdings. Excluding the exceptions noted, no more than 50% of the entity's total Investment portfolio will be invested in a single security type or with a single financial Institution.

**Custodial credit risk, deposits:** For a deposit, this is the risk that in the event of bank failure, Energy Northwest's deposits may not be returned to it. Energy Northwest's demand deposit interest bearing accounts and certificates of deposits are covered up to $250,000 by Federal Depository Insurance (FDIC) while time and savings deposit non-interest-bearing accounts are covered up to an additional $250,000 by FDIC. All interest and non-interest-bearing deposits are covered by collateral held in a multiple financial institution collateral pool administered by the Washington state Treasurer's Local Government Investment Pool (PDPC). Under state law, public depositories under the PDPC may be assessed on a prorated basis if the pool's collateral is insufficient to cover a loss. All deposits are insured by collateral held in the multiple financial institution collateral pool. State law requires deposits may only be made with institutions that are approved by the PDPC.

**Custodial credit risk, investments:** For an investment, custodial credit risk is the risk that, in the event of failure of the counterparty, Energy Northwest will not be able to recover the value of its investments or collateral securities in possession of an outside party. Energy Northwest's investment policy addresses this risk. All securities owned by Energy Northwest are held by a third-party custodian, acting as an agent for Energy Northwest under the terms of a custody agreement.

**Fair Value:** Energy Northwest investments have been adjusted to reflect available fair value as of June 30, 2022, obtained from available financial industry valuation sources. Investments are valued using Bloomberg Investor Service by taking the information available on the last business day of each month. Energy Northwest categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All Energy Northwest fair market measurements are quoted at Level 2.

## Investments (Dollars in thousands)

| | Amortized Cost | Unrealized Gains | Unrealized Losses | Fair Value (1) (2) |
|---|---|---|---|---|
| Columbia | $ 122,353 | $ - | $ (556) | $ 121,797 |
| Packwood | - | - | - | - |
| Nuclear Project No. 1 | - | - | - | - |
| Nuclear Project No. 3 | - | - | - | - |
| Business Development Fund | 4,990 | - | (159) | 4,831 |
| Internal Service Fund | 17,998 | 1 | (752) | 17,247 |
| Nine Canyon Wind | 15,833 | - | (505) | 15,328 |

(1) All investments are in U.S. Government backed securities including U.S. Government Agencies and Treasury Bills.

(2) The majority of investments have maturities of less than 1 year. Approximately $37.7 million have a maturity beyond 1 year with the longest maturity being March 31st, 2026.

## Investment Concentration

| Investment Type | Rating | June 30, 2022 |
|---|---|---|
| Federal Home Loan Bank | AA+ | 31% |
| Federal National Mortgage Assn. | AA+ | 4% |
| U.S. Treasury | AA+ | 65% |
| | | 100% |

**NOTE 4 - Long-Term Debt**

Each Energy Northwest business unit is financed separately. The resolutions of Energy Northwest authorizing issuance of revenue bonds for each business unit provide that such bonds are payable from the revenues of that business unit. All bonds issued under resolutions Nos. 769, 775 and 640 for Nuclear Projects Nos. 1, 3 and Columbia, respectively, have the same priority of payment within the business unit (the "prior lien bonds"). No prior lien bonds remain outstanding related to Columbia authorized under resolution No. 640. No prior lien bonds remain outstanding related to Project 1 authorized under resolution No. 769. No prior lien bonds remain outstanding related to Project 3 authorized under resolution No. 775. All bonds issued under resolutions Nos. 835, 838 and 1042 (the "electric revenue bonds") for Nuclear Projects Nos. 1, 3 and Columbia, respectively, are subordinate to the prior lien bonds and have the same subordinated priority of payment within the business unit. Nine Canyon's bonds were authorized by the following resolutions: Resolution No. 1214 (2001 Bonds), Resolution No. 1299 (2003 Bonds), Resolution No. 1376 (2005 Bonds), Resolution No.1482 (2006 Bonds), Resolution No. 1722 (2012 Bonds), Resolution No. 1789 (2014 Bonds), and Resolution No. 1824 (2015 Bonds). No 2001, 2003, 2005, or 2006 Nine Canyon bonds remained outstanding as of June 30, 2022 under Resolution Nos. 1214, 1299, 1376, and 1482 respectively.

During the year ended June 30, 2022, Energy Northwest issued, for Project 1, Columbia, and Project 3 2022-A fixed-rate bonds. Energy Northwest also issued, for Project 1 and Columbia the 2022-B fixed rate bonds. The Project 1 bonds were Issued with a coupon interest rate ranging from 3.32 percent to 5.00 percent. Columbia bonds were issued with a coupon interest rate ranging from 3.32 percent to 5.00 percent. Project 3 bonds were issued with a coupon Interest rate of 5.00 percent.

The Series 2022-A bonds issued for Project 1, Columbia, and Project 3 are tax-exempt fixed-rate bonds. Series 2022-B bonds issued for Project 1 and Columbia are taxable fixed-rate bonds. The 2022-A and 2022-B bonds were issued in majority to refund prior Project 1, Columbia, and Project 3 bonds and associated unamortized premium (represented as a portion of interest expense) along with the issuance of $122.3 million to fund fiscal year 2023 capital related expenses. The 2022-A refunding bonds resulted in a economic gain of $7.8 million for Project 1, $2.9 million for Columbia, and $0.76 million for Project 3.

Energy Northwest also defeased certain revenue bonds by placing the net proceeds from the refunding bonds in irrevocable trusts to provide for all required future debt service payments on the refunded bonds until the dates of redemption. Accordingly, the trust account assets and liabilities for the defeased bonds are not included in the financial statement. In FY 2022 total defeasements included $89.6 million for Project 1 and $277.4 million for Columbia.

The Weighted Average Coupon Interest Rates and Total Defeased Bonds for 2022-A and 2022-B are presented in the following tables:

### Weighted Average Coupon Interest Rate for Refunded Bonds

| | 2022A | 2022B |
|---|---|---|
| Project 1 | 5.00% | N/A |
| Columbia | 4.89% | N/A |
| Total | 4.92% | N/A |

### Weighted Average Coupon Interest Rate for New Bonds

| | 2022A | 2022B |
|---|---|---|
| Project 1 | 5.00% | 3.32% |
| Columbia | 5.00% | 3.32% |
| Project 3 | 5.00% | N/A |
| Total | 5.00% | 3.32% |

### Total Defeased (Dollars in thousands)

| | | 2022A |
|---|---|---|
| Project 1 | $ | 89,615 |
| Columbia | $ | 277,410 |
| Total | $ | 367,025 |

### 2022 Refunding Results

Outstanding principal on revenue and refunding bonds as of June 30, 2022, and future debt service requirements for these bonds are presented in the following tables:

| 2022-A (Tax-Exempt) Transaction | | Project 1 | | Columbia | | Project 3 |
|---|---|---|---|---|---|---|
| Cash flow difference | | | | | | |
| Old debt service cash flows | $ | 133,133 | $ | 353,880 | $ | 21,011 |
| New debt service cash flows | $ | 132,205 | $ | 478,405 | $ | 30,699 |
| Net cash flow savings (dissavings) | $ | 928 | $ | (124,525) | $ | (9,688) |
| Economic gain / loss | | | | | | |
| Present value of old debt service cash flows | $ | 117,503 | $ | 334,610 | $ | 20,979 |
| Present value of new debt service cash flows | $ | 109,656 | $ | 331,661 | $ | 20,903 |
| Economic Gain (Loss) | $ | 7,846 | $ | 2,949 | $ | 76 |

### Columbia Generating Revenue and Refunding Bonds

(Dollars in thousands)

| Series | Coupon Rate (%) | Serial or Term Maturities | Original Issue Amount | Amount Outstanding |
|---|---|---|---|---|
| 2006D | 5.80 | 7-1-2023 | 3,425 | 3,425 |
| 2009B | 6.80 | 7-1-23/2024 | 18,515 | 9,780 |
| 2010C | 4.82-5.12 | 7-1-23/2024 | 75,770 | 31,770 |
| 2010D | 5.61-5.71 | 7-1-23/2024 | 155,805 | 155,805 |
| 2012E | 2.80-4.14 | 7-1-22/2037 | 748,515 | 158,145 |
| 2014A | 4.00-5.00 | 7-1-23/2040 | 517,720 | 276,680 |
| 2014B | 4.05 | 7-1-2030 | 90,520 | 41,515 |
| 2015A | 4.00-5.00 | 7-1-23/2038 | 330,460 | 291,585 |
| 2015B | 2.81-3.84 | 7-1-24/2038 | 329,175 | 50,475 |
| 2015C | 5.00 | 7-1-30/2031 | 38,525 | 38,525 |
| 2016A | 5.00 | 7-1-23/2032 | 89,055 | 72,525 |
| 2016B | 3.20 | 7-1-2028 | 4,085 | 1,985 |
| 2017A | 5.00 | 7-1-23/2035 | 188,130 | 171,060 |
| 2017B | 3.39 | 7-1-2029 | 3,795 | 3,285 |
| 2018A | 4.00-5.00 | 7-1-23/2034 | 320,510 | 219,250 |
| 2018C | 5.00 | 7-1-23/2034 | 229,025 | 218,395 |
| 2019A | 5.00 | 7-1-23/2038 | 251,575 | 223,065 |
| 2019B | 2.48-3.46 | 7-1-23/2035 | 18,300 | 17,880 |
| 2020A | 4.00-5.00 | 7-1-22/2039 | 288,560 | 285,460 |
| 2020B | 1.15-2.45 | 7-1-22/2032 | 14,830 | 14,830 |
| 2021A | 4.00-5.00 | 7-1-22/2042 | 524,090 | 415,200 |
| 2021B | 0.90-2.35 | 7-1-25/2034 | 100,750 | 100,750 |
| 2022A | 5.00 | 7-1-32/2037 | 396,180 | 396,180 |
| 2022B | 3.32 | 7-1-2025 | 1,655 | 1,655 |
| Revenue bonds payable | | | | $ 3,199,225 |

## Nuclear Project No. 1 Refunding Revenue Bonds

(Dollars in thousands)

| Series | Coupon Rate (%) | Serial or Term Maturities | Amount | Outstanding |
|---|---|---|---|---|
| 2014C | 5.00 | 7-1-25/2027 | 197,110 | 197,110 |
| 2015A | 5.00 | 7-1-27/2028 | 117,815 | 50,345 |
| 2015C | 3.00-5.00 | 7-1-2025 | 44,005 | 44,005 |
| 2016A | 5.00 | 7-1-2025 | 195,525 | 129,910 |
| 2017A | 5.00 | 7-1-26/2028 | 237,685 | 148,070 |
| 2017B | 2.94 | 7-1-2025 | 2,160 | 525 |
| 2020A | 5.00 | 7-1-27/2028 | 52,760 | 52,760 |
| 2020B | 1.15 | 7-1-2022 | 395 | 395 |
| 2021A | 5.00 | 7-1-26/2042 | 69,835 | 69,835 |
| 2021B | 0.90 | 7-1-2025 | 375 | 375 |
| 2022A | 5.00 | 7-1-26/2028/2035 | 99,215 | 99,215 |
| 2022B | 3.32 | 7-1-2025 | 560 | 560 |
| Revenue bonds payable | | | | $ 793,105 |

## Nuclear Project No. 3 Refunding Revenue Bonds

(Dollars in thousands)

| Series | Coupon Rate (%) | Serial or Term Maturities | Original Issue Amount | Amount Outstanding |
|---|---|---|---|---|
| 2014C | 5.00 | 7-1-2028 | 72,305 | 72,305 |
| 2015A | 5.00 | 7-1-25/2026 | 79,040 | 74,585 |
| 2015C | 5.00 | 7-1-2026 | 26,675 | 26,675 |
| 2016A | 5.00 | 7-1-26/2027 | 198,535 | 190,110 |
| 2016B | 3.05 | 7-1-2027 | 5,420 | 4,070 |
| 2017A | 5.00 | 7-1-25/2028 | 154,435 | 141,780 |
| 2017B | 2.94 | 7-1-2025 | 1,645 | 905 |
| 2018C | 4.00-5.00 | 7-1-23/2028 | 399,155 | 399,155 |
| 2021A | 4.00 | 7-1-2042 | 16,675 | 16,675 |
| 2022A | 5.00 | 7-1-2035 | 18,560 | 18,560 |
| Revenue bonds payable | | | | $ 944,820 |

## Nine Canyon Wind Project Revenue and Refunding Bonds

(Dollars in thousands)

| Series | Coupon Rate (%) | Serial or Term Maturities | Original Issue Amount | Amount Outstanding |
|---|---|---|---|---|
| 2012 | 4.00-5.00 | 7-1-22/2023 | 13,750 | 3,025 |
| 2014 | 5.00 | 7-1-22/2023 | 36,750 | 9,615 |
| 2015 | 4.00-5.00 | 7-1-22/2030 | 54,895 | 39,335 |
| Revenue bonds payable | | | | $ 51,975 |

# Debt Service Requirements As of June 30, 2021 (Dollars in thousands)

**Columbia Generating Station**

| FISCAL YEAR* | PRINCIPAL | INTEREST | TOTAL |
|---|---|---|---|
| 6/30/2022 Balance:** | $ 102,585 | $ 72,537 | $ 175,122 |
| 2023 | 290,755 | 149,579 | 440,334 |
| 2024 | 315,905 | 133,665 | 449,570 |
| 2025 | 19,585 | 117,429 | 137,014 |
| 2026 | 18,650 | 116,822 | 135,472 |
| 2027 | 14,960 | 116,169 | 131,129 |
| 2028-2032 | 774,265 | 528,885 | 1,303,150 |
| 2033-2037 | 1,114,705 | 291,224 | 1,405,929 |
| 2038-2042 | 547,815 | 73,809 | 621,624 |
| 2043-2044 | - | - | - |
| | $ 3,199,225 | $ 1,600,119 | $ 4,799,344 |

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2022.

**Nuclear Project No. 1**

| FISCAL YEAR* | PRINCIPAL | INTEREST | TOTAL |
|---|---|---|---|
| 6/30/2022 Balance:** | $ 395 | $ 19,322 | $ 19,717 |
| 2023 | 0 | 39,539 | 39,539 |
| 2024 | 0 | 39,137 | 39,137 |
| 2025 | 237,900 | 39,137 | 277,037 |
| 2026 | 195,225 | 27,578 | 222,803 |
| 2027 | 171,730 | 17,817 | 189,547 |
| 2028-2032 | 153,410 | 15,469 | 168,879 |
| 2033-2037 | 18,195 | 5,979 | 24,174 |
| 2038-2042 | 16,250 | 3,250 | 19,500 |
| | $ 793,105 | $ 207,229 | $ 1,000,334 |

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2022.

Nuclear Project No. 3

| FISCAL YEAR* | PRINCIPAL | INTEREST | TOTAL |
|---|---|---|---|
| 6/30/2022 Balance:** | $ - | $ 22,927 | $ 22,927 |
| 2023 | 68,275 | 46,857 | 115,132 |
| 2024 | 63,290 | 43,499 | 106,789 |
| 2025 | 120,440 | 40,368 | 160,808 |
| 2026 | 175,390 | 34,365 | 209,755 |
| 2027 | 173,690 | 25,614 | 199,304 |
| 2028-2032 | 308,500 | 23,400 | 331,900 |
| 2033-2037 | 18,560 | 6,119 | 24,679 |
| 2038-2042 | 16,675 | 3,335 | 20010 |
| 2043-2044 | - | - | - |
| | $ 944,820 | $ 246,485 | $ 1,191,305 |

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2022.

Nine Canyon Wind Project

| FISCAL YEAR* | PRINCIPAL | INTEREST | TOTAL |
|---|---|---|---|
| 6/30/2022 Balance:** | $ 9,755 | $ 1,202 | $ 10,957 |
| 2023 | 10,255 | 1,916 | 12,171 |
| 2024 | 3,960 | 1,404 | 5,364 |
| 2025 | 4,160 | 1,205 | 5,365 |
| 2026 | 4,370 | 998 | 5,368 |
| 2027 | 4,585 | 779 | 5,364 |
| 2028-2032 | 14,890 | 1,207 | 16,097 |
| | $ 51,975 | $ 8,711 | $ 60,686 |

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2022.

## NOTE 5 - Net Billing

### Security - Nuclear Projects Nos. 1 and 3 and Columbia

The participants have purchased all the capability of Nuclear Projects Nos. 1 and 3 and Columbia. BPA has in turn acquired the entire capability from the participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the business units, participants are obligated to pay Energy Northwest a pro-rata share of the total annual costs of the respective projects, including debt service on bonds relating to each business unit. BPA is then obligated to reduce amounts from participants under BPA power sales agreements by the same amount. The net-billing agreements provide that participants and BPA are obligated to make such payments whether or not the projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output.

On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the projects. Energy Northwest previously entered into an agreement with BPA to provide for continuation of the present budget approval, billing, and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among Energy Northwest and private companies was terminated in FY 1999 (See Note 10).

### Security - Packwood Lake Hydroelectric Project

Power produced by Packwood is provided to the 12 member utilities. The member utilities pay the annual costs, including any debt service, of Packwood and are obligated to pay these annual costs whether Packwood is operational. The Packwood participants also share project revenue to the extent that the amounts exceed project costs.

## NOTE 6 - Pension Plans

The following table represents the aggregate pension amounts for all plans as of and for the fiscal year ended June 30, 2022 (in thousands):

| | | |
|---|---|---|
| Pension Liabilities | $ | 12,128 |
| Pension Assets | $ | (127,200) |
| Deferred Outflows of Resources | $ | 24,428 |
| Deferred Inflows of Resources | $ | 136,092 |
| Pension Expense | $ | (27,718) |

State Sponsored Pension Plans - Substantially all of Energy Northwest's full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing, multiple-employer public employee defined benefit and defined contribution retirement plans. The state Legislature establishes, and amends, laws pertaining to the creation and administration of all public retirement systems.

The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available annual comprehensive financial report (ACFR) that includes financial statements and required supplementary information for each plan. The DRS ACFR may be obtained by writing to:

Department of Retirement Systems
Communications Unit
PO Box 48380
Olympia, WA 98540-8380

Or the DRS ACFR may be downloaded from the DRS website at www.drs.wa.gov.

**Public Employees Retirement System (PERS)**

PERS members include elected officials; state employees; employees of the Supreme, Appeals and Superior Courts; employees of the legislature; employees of district and municipal courts; employees of local governments; and higher education employees not participating in higher education retirement programs. PERS is comprised of three separate pension plans for membership purposes. PERS plans 1 and 2 are defined benefit plans, and PERS plan 3 is a defined benefit plan with a defined contribution component.

**PERS Plan 1** - provides retirement, disability, and death benefits. Retirement benefits are determined as 2% of the member's average final compensation (AFC) times the member's years of service. The AFC is the average of the member's 24 highest consecutive service months. Members are eligible for retirement from active status at any age with at least 30 years of service, at age 55 with at least 25 years of service, or at age 60 with at least 5 years of service. Members retiring from active status prior to the age of 65 may receive actuarially reduced benefits. Retirement benefits are actuarially reduced to reflect the choice of a survivor benefit. Other benefits include duty and nonduty disability payments, an optional cost-of-living adjustment (COLA), and a one-time duty-related death benefit, if found eligible by the Department of Labor and Industries. PERS 1 members were vested after the completion of 5 years of eligible service. The plan was closed to new entrants on September 30, 1977.

**Contributions** - The PERS Plan 1 member contribution rate is established by State statute at 6%. The employer contribution rate is developed by the Office of the State Actuary and includes an administrative expense component that is currently set at 0.18%. Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates.

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) were as follows for the fiscal year ended June 30, 2022:

| PERS Plan 1 Actual Contribution Rates | Employer | Employee |
|---|---|---|
| PERS Plan 1 | 10.07% | 6.00% |
| Administrative Fee | 0.18% | |
| Total | 10.25% | 6.00% |

Energy Northwest's actual contributions to the plan were $5,921 thousand for the fiscal year ended June 30, 2022.

**PERS Plan 2/3** - provides retirement, disability, and death benefits. Retirement benefits are determined as 2% of the member's average final compensation (AFC) times the member's years of service for Plan 2 and 1% of AFC for Plan 3. The AFC is the average of the member's 60 highest-paid consecutive service months. There is no cap on years of service credit. Members are eligible for retirement with a full benefit at 65 with at least 5 years of service credit. Retirement before age 65 is considered an early retirement. PERS Plan 2/3 members who have at least 20 years of service credit and are 55 years of age or older, are eligible for early retirement with a benefit that is reduced by a factor that varies according to age for each year before age 65. PERS Plan 2/3 members who have 30 or more years of service credit and are at least 55 years old can retire under one of two provisions:

- With a benefit that is reduced by 3% for each year before age 65, or
- With a benefit that has a smaller (or no) reduction (depending on age) that imposes stricter return-to-work rules.

PERS Plan 2/3 members hired on or after May 1, 2013 have the option to retire early by accepting a reduction of 5% for each year of retirement before age 65. This option is available only to those who are age 55 or older and have at least 30 years of service credit. PERS Plan 2/3 retirement benefits are also actuarially reduced to reflect the choice of a survivor benefit. Other PERS Plan 2/3 benefits include duty and nonduty disability payments, a cost-of-living allowance (based on the CPI), capped at 3% annually and a one-time duty related death benefit, if found eligible by the Department of Labor and Industries. PERS 2 members are vested after completing 5 years of eligible service. Plan 3 members are vested in the defined benefit portion of their plan after 10 years of service; or after 5 years of service if 12 months of that service are earned after age 44.

**PERS Plan 3** - defined contribution benefits are totally dependent on employee contributions and investment earnings on those contributions. PERS Plan 3 members choose their contribution rate upon joining membership and have a chance to change rates upon changing employers. As established by statute, Plan 3 required defined contribution rates are set at a minimum of 5% and escalate to 15% with a choice of 6 options. Employers do not contribute to the defined contribution benefits. PERS Plan 3 members are immediately vested in the defined contribution portion of their plan.

**Contributions** - The PERS Plan 2/3 employer and employee contribution rates are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. The Plan 2/3 employer rates include a component to address the PERS Plan 1 unfunded actuarially accrued liability (UAAL) and an administrative expense that is currently set at 0.18%. Each biennium, the state Pension Funding Council adopts Plan 2 employer and employee contribution rates and Plan 3 contribution rates.

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) were as follows fiscal year ended June 30, 2021:

| PERS Plan 2/3 Actual Contribution Rates | Employer 2/3 | Employee 2 | Employee 3 |
|---|---|---|---|
| PERS Plan 2/3 | 6.36% | 6.36% | Varies |
| PERS Plan 1 UAAL | 3.71% | | |
| Administrative Fee | 0.18% | | |
| Total | 10.25% | 6.36% | Varies |

Energy Northwest's actual contributions to the plan were $10,117 thousand for the fiscal year ended June 30, 2022.

### Actuarial Assumptions

The total pension liability/(asset) (TPL/A) for each of the DRS plans was determined using the most recent actuarial valuation completed in 2021 with a valuation date of June 30, 2020. The actuarial assumptions used in the valuation were based on the results of the Office of the State Actuary's (OSA) 2013-2018 Demographic Experience Study and the 2019 Economic Experience Study.

Additional assumptions for subsequent events and law changes are current as of the 2020 actuarial valuation report. The TPL/A was calculated as of the valuation date and rolled forward to the measurement date of June 30, 2021. Plan liabilities/(assets) were rolled forward from June 30, 2020, to June 30, 2021, reflecting each plan's normal cost (using the entry-age cost method), assumed interest and actual benefit payments.

- Inflation: 2.75% total economic inflation; 3.50% salary inflation
- Salary increases: In addition to the base 3.50% salary inflation assumption, salaries are also expected to grow by promotions and longevity.
- Investment rate of return: 7.4%

Mortality rates were developed using the Society of Actuaries' Pub. H-2010 mortality rates, which vary by member status, as the base table. The OSA applied age offsets for each system, as appropriate, to better tailor the mortality rates to the demographics of each plan. OSA applied the long-term MP-2017 generational improvement scale, also developed by the Society Actuaries, to project mortality rates for every year after the 2010 base table. Mortality rates are applied on a generational basis; meaning, each member is assumed to receive additional mortality improvements in each future year throughout his or her lifetime.

There were no changes in assumptions between the 2021 and 2020 valuations. There were changes in methods between the 2021 and 2020 valuations.

- For purposes of the June 30, 2020 Actuarial Valuation Report (AVR), a non-contribution rate setting valuation under current funding policy, the Office of the State Actuary (OSA) introduced temporary method changes to produce asset and liability/(asset) measures as of the valuation date. See high-level summary below. OSA will revert back to the methods outlined in the 2019 AVR when preparing the 2021 AVR, a contribution rate-setting valuation, which will serve as the basis for 2022 ACFR results.
- To produce measures at June 30, 2020, unless otherwise noted in the 2020 AVR, OSA relied on the same data, assets, methods, and assumptions as the June 30, 2019 AVR. OSA projected the data forward one year reflecting assumed new hires and current members exiting the plan as expected. OSA estimated June 30, 2020, assets by relying on the fiscal year end 2019 assets, reflecting actual investment performance over FY 2020, and reflecting assumed contribution amounts and benefit payments during FY 2020. OSA reviewed the actual June 30, 2020, participant and financial data to determine if any material changes to projection assumptions were necessary. OSA also considered any material impacts to the plans from 2021 legislation. See the 2020 AVR for more information.

### Discount Rate

The discount rate used to measure the total pension liability for all DRS plans was 7.4%.

To determine that rate, an asset sufficiency test was completed to test whether each pension plan's fiduciary net position was sufficient to make all projected future benefit payments for current plan members. Based on OSA's assumptions, the pension plans' fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return of 7.4% was used to determine the total liability/(asset).

## Long-Term Expected Rate of Return

The long-term expected rate of return on the DRS pension plan investments of 7.4% was determined using a building-block-method. In selecting this assumption, the Office of the State Actuary (OSA) reviewed the historical experience data, considered the historical conditions that produced past annual investment returns, and considered capital market assumptions and simulated expected investment returns provided by the Washington State Investment Board (WSIB). The WSIB uses the capital market assumptions and their target asset allocation to simulate future investment returns over various future times.

## Estimated Rates of Return by Asset Class

Best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation, are summarized in the table below. The inflation component used to create the table is 2.2% and represents the WSIB's most recent long-term estimate of broad economic inflation.

Best estimates as of June 30, 2021:

| Asset Class | Target Allocation | Percent Long-Term Expected Real Rate of Return Arithmetic |
|---|---|---|
| Fixed Income | 20% | 2.20% |
| Tangible Assets | 7% | 5.10% |
| Real Estate | 18% | 5.80% |
| Global Equity | 32% | 6.30% |
| Private Equity | 23% | 9.30% |
| Total | 100% | |

## Sensitivity of NPL/(Asset)

The table below presents Energy Northwest's proportionate share of the net pension liability/(asset) calculated using the discount rate of 7.4%, as well as what Energy Northwest's proportionate share of the net pension liability/(asset) would be if it were calculated using a discount rate that is 1 percentage point lower (6.4%) or 1-percentage point higher (8.4%) than the current rate (in thousands).

| | 1% Decrease (6.4%) | Current Discount Rate (7.4%) | 1% Increase (8.4%) |
|---|---|---|---|
| PERS 1 | $ 20,661 | $ 12,128 | $ 4,687 |
| PERS 2/3 | (36,237) | (127,200) | (202,108) |

The pension liability has been allocated to the business units based on the percentages listed in Note 1. The total pension liability for each unit as of June 30, 2022 is as follow (in thousands):

| | Energy Northwest's proportionate share of the PERS Plan 1 net pension liability: | Energy Northwest's proportionate share of the PERS Plan 2/3 net pension liability: | Total |
|---|---|---|---|
| Columbia | $ 11,290 | $ (118,411) | $ (107,121) |
| Packwood | 53 | (560) | (507) |
| Business Development | 626 | (6,563) | (5,937) |
| Nine Canyon | 112 | (1,170) | (1,058) |
| Nuclear Project No. 1 | 47 | (496) | (449) |
| Total | $ 12,128 | $ (127,200) | $ (115,072) |

## Pension Plan Fiduciary Net Position

Detailed information about the State's pension plans' fiduciary net position is available in the separately issued DRS financial report.

Pension Liabilities (Assets), Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

At June 30, 2022 Energy Northwest reported a total pension liability (asset) for its proportionate share of the net pension liabilities as follows (measured as of June 30, 2021 in thousands):

| | | |
|---|---|---|
| PERS 1 | $ | 12,128 |
| PERS 2/3 | | (127,200) |
| Total | $ | (115,072) |

Energy Northwest's proportionate share of the collective net pension assets, deferred outflows, liabilities, and deferred inflows was as follows:

| | Proportionate Share 6/30/20 | Proportionate Share 6/30/21 | Change in Proportion |
|---|---|---|---|
| PERS 1 | 0.89% | 0.99% | 0.10% |
| PERS 2/3 | 1.16% | 1.28% | 0.12% |

Employer contribution transmittals received and processed by the DRS for the fiscal year ended June 30 are used as the basis for determining each employer's proportionate share of the collective pension amounts reported by the DRS in the Schedules of Employer and Nonemployer Allocations.

## Pension Expense

For the fiscal year ended June 30, 2021, Energy Northwest's recognized pension expense as follows (in thousands):

| | | |
|---|---|---|
| PERS 1 | $ | 1,434 |
| PERS 2/3 | | (29,423) |
| Expenses | | 271 |
| Total | $ | (27,718) |

### Deferred Outflows of Resources and Deferred Inflows of Resources

At June 30, 2022, Energy Northwest reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources (in thousands):

| | Deferred Outflows of Resources | Deferred Inflows of Resources |
|---|---|---|
| **PERS 1:** | | |
| Differences between expected and actual economic experience | $ - | $ - |
| Changes in actuarial assumptions | - | - |
| Net difference between projected and actual investment earnings on pension plan investments | - | 13,458 |
| Changes in proportion and differences between contributions and proportionate share of contributions | - | - |
| Contributions paid to PERS subsequent to the measurement date | 5,619 | - |
| Total PERS 1 | $ 5,619 | $ 13,458 |
| **PERS 2/3:** | | |
| Differences between expected and actual economic experience | $ 6,178 | $ 1,559 |
| Changes in actuarial assumptions | 186 | 9,033 |
| Net difference between projected and actual investment earnings on pension plan investments | - | 106,310 |
| Changes in proportion and differences between contributions and proportionate share of contributions | 2,818 | 5,732 |
| Contributions paid to PERS subsequent to the measurement date | 9,627 | - |
| Total PERS 2/3 | 18,809 | 122,634 |
| Total All Plans | $ 24,428 | $ 136,092 |

Deferred outflows of resources related to pensions resulting from the District's contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability or an addition to the net pension asset in the following year. Other amounts reported as deferred outflows and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

| Fiscal Year Ended June 30 | PERS 1 | PERS 2/3 |
|---|---|---|
| 2023 | $ (3,565) | $ (29,677) |
| 2024 | (3,267) | (27,767) |
| 2025 | (3,089) | (26,860) |
| 2026 | (3,537) | (28,707) |
| 2027 | - | (662) |
| Thereafter | - | 221 |
| Total | $ (13,458) | $ (113,452) |

## NOTE 7 - Deferred Compensation Plans

Energy Northwest provides a 401(k) deferred compensation plan (401(k) plan), and a 457 deferred compensation plan. Both plans are defined contribution plans that were established to provide a means for investing savings by employees for retirement purposes. All permanent, full-time employees are eligible to enroll in the plans. Participants are immediately vested in their contributions and direct the investment of their contribution. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations.

For the 401(k) plan, Energy Northwest may elect to make an employer matching contribution for each of its employees who is a participant during the plan year. The amount of such an employer match shall be 50 percent of the maximum salary deferral percentage. During FY 2022 Energy Northwest contributed $4.2 million in employer matching funds while employees contributed $12.4 million.

## NOTE 8 - Nuclear Licensing and Insurance

### Nuclear Licensing

Energy Northwest is a licensee of the Nuclear Regulatory Commission ("NRC") and is subject to routine licensing and user fees. Additionally, Energy Northwest may be subject to license modification, suspension, revocation, or civil penalties in the event regulatory or license requirements are violated.

### Nuclear Insurance

Nuclear insurance includes liability coverage, property damage, decontamination and premature decommissioning coverage and accidental outage and/or extra expense coverage. The liability coverage is governed by the Price-Anderson Act (Act), while the property damage, decontamination and premature decommissioning coverage are defined by the Code of Federal Regulations. Energy Northwest continues to maintain all regulatory required limits as defined by the NRC, Code of Federal Regulations, and the Act. The NRC requires Energy Northwest to certify nuclear insurance limits on an annual basis. Energy Northwest intends to maintain insurance against nuclear risks to the extent such insurance is available on reasonable terms and in an amount and form consistent with customary practice. Energy Northwest is self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Such losses could have an effect on Energy Northwest's results of operations and cash flows. All dollar figures noted below are as of June 30, 2022.

American Nuclear Insurance (ANI) Coverage: The Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $13.523 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection (SFP). Energy Northwest has $450 million of liability insurance as the first layer of protection. If any US nuclear generation plant has a significant event which exceeds the plant's first layer of protection, every operating licensed reactor in the US is subject to an assessment up to $137.61 million. Assessments are limited to $20.496 million per reactor, per year, per incident, excluding tax. The SFP is adjusted at least every 5 years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

Nuclear Electrical Insurance Limited (NEIL) Coverage: The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1.06 billion nuclear decontamination and property damage insurance and requires the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Energy Northwest has aggregate coverage in the amount of $2.75 billion which is subject to a $5 million deductible per accident.

The Agency anticipates exposure to a variety of risks of loss as a normal part of conducting business (for example: torts; theft of, damage to, or destruction of assets; errors and omissions; workers compensation). These anticipated risks of losses are covered through a combination of self-insurance, commercial property and liability insurance, nuclear property and liability insurance, professional services liability insurance, Directors & Officers (including employment practices liability) insurance, and fiduciary insurance. Claims for loss to the Agency are infrequent and have not exceeded the liability policy limits in the past three years.

**NOTE 9 - Decommissioning and Site Restoration - Asset Retirement Obligation (ARO)**

Energy Northwest implemented GASB Statement No. 83 - "Certain Asset Retirement Obligations" and applied the statement in fiscal year 2019. For the purposes of this statement, an ARO is a legally enforceable liability associated with the retirement of a tangible capital asset (that is, the tangible capital asset is permanently removed from service). The retirement of a tangible capital asset encompasses its sale, abandonment, recycling, or disposal in some manner; however, it does not encompass temporary idling of a tangible capital asset.

AROs result from the normal operations of a tangible capital assets, whether acquired or constructed, and include legally enforceable liabilities with all the following activities:

- Retirement of a tangible capital asset
- Disposal of a replaced part that is a component of a tangible capital asset
- Environmental remediation associated with the retirement of a tangible capital asset that results from the normal operation of that capital asset

The measurement of Energy Northwest's AROs are based on the best estimate of the current value of outlays expected to be incurred. Current value is the amount that would be paid if all equipment, facilities, and services included in the estimate were acquired at the end of the accounting period. The current estimate is the basis for the ARO and corresponding liability. The recognition of the ARO at current value also results in a corresponding deferred outflow of resources.

Energy Northwest has identified the following AROs subject to GASB No. 83:

- Columbia Generating Station (includes related Columbia Site Restoration)
- Independent Spent Fuel Storage Installation (ISFSI)
- Nine Canyon Wind Farm
- Nuclear Project No. 1 site restoration
- Horn Rapid Battery Energy Storage System (BESS)
- Excluded from GASB No. 83 reporting is the Packwood Hydroelectric Project. The timing and extent of any liabilities associated with operations is not determinable at this time. Packwood remains operable with no foreseeable change in operations; assumptions is the current facility is not subject to the requirements of obtaining a current estimate of a liability with offset to deferred outflows. As such, Packwood's obligation has not been calculated because the time frame and extent of the obligation under this statement was considered indeterminate. As a result, no estimate of the ARO obligation was completed; an ARO will be recorded if future events warrant a change.

Decommissioning and site restoration requirements for Columbia, ISFSI are governed by the NRC regulations. Columbia, ISFSI and Nuclear Project No. 1 are also governed by site certification agreements between Energy Northwest and the state of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC) and a lease agreement with the Department of Energy ("DOE"). (See Notes 1 & 10). Nine Canyon decommissioning requirements are governed by participant agreements which are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Agreement and associated land leases for location of the wind turbines. The BESS decommissioning requirements are governed by a participant agreement with the City of Richland.

## Decomissioning activity

### Columbia Generation Station (including site restoration)

Columbia is a 1,174-megawatt electric (MWe Design Electric rating, net) boiling water reactor located on the DOE Hanford Site north of Richland, Washington.

Columbia was issued a construction permit in March of 1973 and NRC licensing was completed in December of 1983. Columbia began commercial generation in December of 1984. The estimate for the ARO was updated in February of 2019 to account for the liability associated with the dismantling and decommissioning of the Columbia asset along with restoration of the leased DOE land. Both the asset decommissioning and site restoration are governed by agreements and regulations signed as part of construction and completion of Columbia.

The FY 2019 Columbia study was a joint effort between BPA and Energy Northwest to comply with the provisions of adopting GASB No. 83 to provide a current estimate for future accounting and funding requirements. The study was completed by a national firm that is involved with approximately 90% of cost studies completed in the United States nuclear industry. Original plan specifications and drawings were used as basis for costing estimates and mapped for design changes that have occurred since construction. Current estimates for labor and materials were obtained and used as basis for coming up with the estimates of work to be performed. Phasing of the costs were scheduled and flowed according to two scenarios currently accepted by the NRC, DECON and SAFSTOR.

- DECON - method in which structures, systems, and components that contain radioactive contamination are removed from a site and safely disposed at a commercially operated low-level waste disposal facility or decontaminated to a level that permits the site to be released for unrestricted use shortly after it ceases operation.
- SAFSTOR - method in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use.

Both DECON and SAFSTOR are acceptable methods of accounting for decommissioning estimates with differences in method and timing of when the expenditures will occur after termination of the plant (currently planned for December 2043). A joint decision between BPA and Energy Northwest was made to adopt the DECON method for accounting purposes.

The Columbia study estimate using DECON as the scenario has an estimated decommissioning activity completion date of June 2097. In FY 2022, $28.9 million of amortization expense was recognized and the index adjustment for FY 2022 was $132.6 million resulting in the overall increase in deferred outflow of $103.7 million. The index adjustment increased the estimated liability as of June 30, 2022 from $1.54 billion to $1.67 billion.

Each year the ARO is evaluated to determine if there are any material changes in timing or costs. If there are material changes, the estimate will be adjusted accordingly. If there are no material changes impacting the estimate, then a standard index will be used each year to determine current changes to the estimated derived from the original study. The amount for both the liability and deferred outflow will be increased or decreased accordingly and change the out year straight line amount for decommissioning. There were no material changes in timing or costs related to the Columbia ARO.

At the time of termination of Columbia and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the estimated completion date of FY 2097. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment a gain or loss on the ARO will be recorded for the difference. However, regarding the net-billed projects, BPA is obligated to provide for the entire cost of decommissioning and site restoration; therefore, any gain or loss recognized upon settlement of the ARO results in an adjustment to either the billings in excess of costs (liability) or costs in excess of billings (asset), as appropriate, as no net revenue or loss is recognized, and no net position is accumulated for the net-billed projects.

### Independent Spent Fuel Storage Installation

Energy Northwest's Independent Spent Fuel Storage Installation (ISFSI) at the Columbia Generating Station is a temporary dry cask storage facility intended to store spent nuclear reactor fuel in NRC-approved dry storage casks until the DOE completes its plan for a national repository. The ISFSI consists of two concrete pads storing a total of 36 casks and one additional pad with the capacity of 18 casks. The last ISFSI campaign, which began in March 2022, was completed in May 2022 for an additional nine casks. In order to accommodate spent fuel to be generated through the end of the plant's operating license period of December 20, 2043, Energy Northwest is expanding the ISFSI facility to store an additional 72 casks. The final phase of the ISFSI pad expansion project will be completed in the FY 2021-2024-time frame and commissioned in FY 2025, the four additional pads will have capacities of 18 casks each. Energy Northwest previously financed a portion of the cost for the construction of the existing ISFSI pads.

No additional issues are anticipated with the ISFSI expansion project. However, the NRC is in the process of developing additional security rulemaking that may potentially impose additional requirements beyond currently planned security controls. The extent of those additional requirements or when they will be imposed on Columbia are not known at this time but are not anticipated to become effective within the next two or three years.

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Annual payments to a fund established pursuant to this plan began in 2003 and were held by Energy Northwest. These payments were currently scheduled to occur annually through 2044. Adoption of asset retirement accounting for the ISFSI project took place in FY 2005. The Columbia cost study completed in February 2019 included the ISFSI and revised both the timing and estimate. ISFSI decommissioning is projected to be completed in a five-month period in 2097 under the DECON scenario and is estimated at $7.5 million (in 2019 dollars). In FY 2022, $214 thousand of amortization expense was recognized and the index adjustment for FY 2022 was $688 thousand resulting in the overall increase in deferred outflow of $474 thousand. The index adjustment increased the estimated liability as of June 30, 2022, from $8.0 million to $8.6 million.

Each year the ARO evaluation for the ISFSI is included as part of the Columbia review, as such, accounting and any eventual net-billed project impacts will follow the same process described above for the Columbia ARO and net-billed obligations.

The above estimates and timing do not consider any of the impacts of the current DOE litigation or potential changes in DOE handling of accumulated spent fuel being stored at the ISFSI. Note 10 - Commitments and Contingencies under other litigations and commitments describes the current status of the ISFSI settlement.

On March 21, 2021 Energy Northwest agreed to transfer existing ownership of the ISFSI trust fund to Bonneville, allowing Bonneville to appropriately manage the ISFSI fund, and in addition, access investment options unavailable to Energy Northwest under current law. Similar to the Columbia trust fund agreement with Bonneville, Energy Northwest retains all rights duties and obligations related to the decommissioning and remediation of the ISFSI facility.

### Nine Canyon Wind Project

The Nine Canyon Wind Project (Nine Canyon) is wholly owned and operated by Energy Northwest on leased ground located in the Horse Heaven Hills area southwest of Kennewick, Washington in Benton County. Electricity generated by Nine Canyon is purchased undersigned agreements with an end date of 2030. Under the current agreement, Nine Canyon has the obligation to remove the generation facilities upon expiration of the lease agreement if requested by the lessors. The Nine Canyon Wind Project recorded the related original ARO in FY 2003 for Phase I and II. Phase III began commercial operation in FY 2008 and the original ARO was adjusted to reflect the change in scenario for the retirement obligation, with current lease agreements reflecting a 2030 expiration date. Previous scenarios for the ARO have been factored into the participant agreements, derives the rate plan, and drives the cash requirements for debt repayment and cost of operations. Possible adjustments may be necessary to future rates depending on operating costs and any changes to the ARO.

A cost estimate was completed in FY 2018 for Nine Canyon and revised both the timing and estimate of decommissioning activities. The Nine Canyon decommissioning is projected to be completed following the 2030 expiration date of the power purchase and lease agreements and was estimated at $18.0 million (in 2019 dollars). In FY 2022, $792 thousand of amortization expense was recognized and the index adjustment for FY 2022 was $1.64 million resulting in the overall increase in deferred outflow of $846 thousand. The index adjustment also increased the estimated liability as of June 30, 2022, from $19.0 million to $20.7 million.

Each year the ARO will be evaluated to determine if there are any material changes in timing or costs. If there are material changes, the estimate will be adjusted accordingly. If there are no material changes impacting the estimate, then a standard index will be used each year to determine current changes to the estimated derived from the original study. The amount for both the liability and deferred outflow will be increased or decreased accordingly and change the out year straight line amount for decommissioning. There were no material changes in timing or costs for the Nine Canyon ARO.

At the time of termination of Nine Canyon and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the estimated completion date of FY 2031. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment a gain or loss on the ARO will be recorded for the difference.

### Nuclear Project No. 1

Project 1 is a partially completed nuclear electric generating project located on DOE's Hanford reservation, approximately one and one-half miles east of Columbia. Project 1 was terminated in May 1994. Energy Northwest has planned for the demolition and restoration of Nuclear Project No. 1 and is now maintaining the site to support re-use activities. The Nuclear Project No. 1 Post Termination agreement requires BPA to fund this site remediation plan. The current plan estimates final decommissioning (site remediation) to be complete in June 2023. The estimate from FY 2021 was updated to reflect some updated costs to be incurred; the remaining estimate was $6.2 million as of June 30, 2021. The June 30, 2021 estimate was revised upward by $1.9 million; FY 2022 costs incurred of $4.1 million resulted in the remaining estimate of $4.0 million. Total site remediation activity costs to date are $18.4 million. Due to the re-valuation of the ARO estimate each year there are no prior year accounting impacts to the Nuclear Project No. 1 ARO as a result of adopting GASB No. 83. The asset retirement calculation has been adjusted yearly for actual costs incurred and yearly revised estimates. BPA has placed funds in an external interest-bearing trust account in order to have sufficient funds for ongoing remediation costs. The amount in the trust fund is approximately $18.0 million as of June 30, 2022. Any funds remaining after final remediation efforts are complete will be returned to BPA.

### Horn Rapids Battery Storage System

The Horn Rapids Battery Energy Storage System (BESS) is a collaborative effort between Energy Northwest and the City of Richland and is part of an overall project effort commonly known as the Horn Rapids Solar, Storage, and Training Project (HRSST). HRSST Is a four MWdc Photovoltaic solar project (Energy Northwest does not own the solar portion) paired with a 1 MW/4 MWh basic lithium-ion battery storage system. Energy Northwest will operate and maintain the BESS portion of the project for the City of Richland. The City of Richland has signed a purchase power agreement for 100% of the power and reimbursement of construction and operating costs of the BESS. The BESS is located on leased property in Richland Washington. The BESS was essentially complete and operational June 30, 2021.

Total BESS projected costs were estimated at $6.4 million, with $6.3 million incurred as of June 30, 2022. The estimate for the grant closure requirements involving analytics and testing is $0.1 million. Energy Northwest was the recipient of a Washington State Department of Commerce (Commerce) grant in 2017. Commerce awarded up to $3.0 million under the Clean Energy Funds' Grid Modernization Grant Program to offset the construction of the BESS. Grant proceeds received as of June 30, 2022, were $2.6 million with the remainder of $0.4 million to be billed in FY 2023 after analytics and testing is complete. Decommissioning costs are part of the agreement for reporting operating costs under the City of Richland participant agreement, therefore financial assurance is for total costs to be reimbursed by the City of Richland under the existing participant agreement. The decommissioning plan was finalized as part of the project deliverables prior to operation. Projected decommissioning costs are $40 thousand in 2021 dollars and expected to be incurred after 25 years of operation. In FY 2022, $1 thousand of amortization expense was recognized and the index adjustment for FY 2022 was $3 thousand resulting in the overall increase in deferred outflow of $2 thousand. The index adjustment also increased the estimated liability as of June 30, 2022, from $40 thousand to $43 thousand.

### ARO Financial Assurance

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on providing financial assurance for decommissioning plants at the end of each plant's operating life. In September 1998, the NRC approved and published its "Final Rule on Financial Assurance Requirements for Decommissioning Power Reactors." As provided in this rule, each power reactor licensee is required to report to the NRC the status of its decommissioning funding for each reactor or share of a reactor it owns. This reporting requirement began March 31, 1999, and reports are required every two years thereafter. Energy Northwest submitted its most recent report to the NRC for Columbia decommissioning in March 2021. A separate requirement for providing financial assurance for ISFSI decommissioning states that a report must be provided at least every three years. Energy Northwest submitted its most recent report to the NRC for ISFSI decommissioning in November 2021.

Energy Northwest's assurance funding estimate (10 CFR 50.75 - Reporting and Recordkeeping for Decommissioning) of Columbia's plant decommissioning costs in FY 2020 dollars is $569.3 million and assurance funding estimate (10 CFR 72.30 - Reporting and Recordkeeping for Decommissioning) of Columbia's ISFSI decommissioning costs in FY 2021 dollars is $7.1 million. These estimates are updated biannually for the Columbia decommissioning and every three years for the ISFSI decommissioning with the last update for the Columbia occurring in fiscal year 2021 and for the ISFSI in fiscal year 2022. The estimates are based on the NRC minimum amount (NRC 2021 study for both Columbia and the ISFSI) required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

Site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the site certification agreements between Energy Northwest and the state of Washington and by regulations adopted by the EFSEC. Energy Northwest submitted a site restoration plan that was approved by the EFSEC on June 12, 1995. Energy Northwest's funding estimate of Columbia's site restoration costs in FY 2020 dollars is $105.1 million and is updated biannually along with the Columbia decommissioning estimate. Both decommissioning and site restoration estimates are used as the basis for establishing a funding plan that includes escalation and interest earnings until decommissioning activities occur. Payments to the decommissioning and site restoration funds have been made since January 1985.

The fair value of cash and investment securities in the Columbia decommissioning, ISFSI decommissioning and site restoration funds as of June 30, 2022, totaled approximately $371.1 million, $2.5 million, and $57.5 million, respectively. The fair value of cash and investment securities in the site restoration fund for Nuclear Project No. 1 is $18.0 million.

Since September 1996, the Columbia and Nuclear Project No. 1 amounts have been held in an irrevocable trust that recognizes asset retirement obligations according to the fair value of the dismantlement and restoration costs of certain Energy Northwest assets. The ISFSI amounts were transferred from Energy Northwest to Bonneville as discussed above and are held in same manner as the trust funds mentioned for both Columbia and Nuclear Project No. 1. The trustee is a domestic U.S. bank that certifies the funds for use when needed to retire the asset. The trusts are funded by BPA ratepayers and managed by BPA in accordance with NRC requirements and site certification agreements; the balances in these external trust funds are not reflected on Energy Northwest's balance sheet.

Nine Canyon billing rates to power purchase participants are set to cover cash requirements of debt repayment and cost of operations. Any increases or decreases to rates will be based on cost of operations in the future. Adjustments to billing rates may be necessary in the future to cover estimated costs incurred for the eventual decommissioning of Nine Canyon.

Financial assurance and estimates for Nuclear Project No. 1 are discussed in the previous section - Decommissioning - Nuclear Project No. 1.

Financial assurance and estimates for the BESS are discussed in the previous section – Decommissioning – Horn Rapids Battery Storage System.

## NOTE 10 - Commitments and Contingencies

### Nuclear Project No. 1 Termination

Since the Nuclear Project No.1 termination, Energy Northwest has been planning for the demolition of Nuclear Project No. 1 and restoration of the site, recognizing the fact that there is no market for the sale of the project in its entirety, and no viable alternative use has been found to-date. The final level of demolition and restoration will be in accordance with agreements discussed below under "Nuclear Project No. 1 Site Restoration."

### Nuclear Project No. 3 Termination

In June 1994, the Nuclear Project No. 3 Owners Committee voted unanimously to terminate the project. In 1995, a group from Grays Harbor County, Washington, formed the Satsop Redevelopment Project (SRP). The SRP introduced legislation with the state of Washington under Senate Bill No. 6427, which passed and was signed by the governor of the state of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 exists for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights. In February 1999, Energy Northwest entered into a transfer agreement with the SRP to transfer the real and personal property at the site of Nuclear Project No. 3. The SRP also agreed to assume regulatory responsibility for site restoration. Therefore, Energy Northwest is no longer responsible to the state of Washington and EFSEC for any site restoration costs.

### Nuclear Project No. 1 Site Restoration

Site restoration requirements for Nuclear Project No. 1 are governed by site certification agreements between Energy Northwest and the state of Washington and regulations adopted by EFSEC, and a lease agreement with DOE. Energy Northwest submitted a site restoration plan for Nuclear Project No. 1 to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment, or other techniques such that the sites pose minimal hazard to the public. EFSEC approved Energy Northwest's site restoration plan on June 12, 1995. In its approval, EFSEC recognized that there is uncertainty associated with Energy Northwest's proposed plan. Accordingly, EFSEC's conditional approval provides for additional reviews once the details of the plan are finalized. The plan is updated every five years with the last update submitted in 2019.

### Business Development Fund Interest in Northwest Open Access Network (NoaNet)

Energy Northwest, along with 9 other Washington State public entities, is a member of NoaNet, a Washington nonprofit mutual corporation. NoaNet was formed in February 2000 to provide broadband communications over public benefit fibers leased from Bonneville Power Administration throughout the Pacific Northwest. The network began commercial operation in January 2001.

As a member of NoaNet as allowed by RCW 54.16, Energy Northwest has guaranteed certain portions of NoaNet debt based on its proportionate membership share. Energy Northwest's membership share is 8.04% with a step-up provision of 25 percent of the membership share. NoaNet reserves the right to assess the members to cover deficits from operations. In November 2020 NoaNet obtained bond funding for $25 million with $20.1 million outstanding in December 2021; EN backed this debt at 10%. In Calendar Year 2021 NoaNet met all the debt obligations through profitable operations. There have been no assessments since 2011.

NoaNet did report a decrease in net position (excluding grant proceeds) of $2.9 million for Calendar Year 2021. In accordance with GAAP, Energy Northwest did not record their proportionate share of these gains/losses.

Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, Chief Financial Officer, 7195 Wagner Way, Suite 104, Gig Harbor, WA 98335.

### Other Litigation and Commitments

Energy Northwest is a party to various claims and legal actions arising in the normal course of business. The following is a discussion of certain litigation and claims relating to the Net Billed Projects to which Energy Northwest is a party:

Energy Northwest v. United States of America (DOE). On August 28, 2014, Energy Northwest and the United States entered into a Settlement Agreement ("Settlement Agreement") under Energy Northwest v. United States, No. 11-447C (Fed. Cl. filed July 7, 2011). In addition to settling litigation for the U.S. Department of Energy's ("DOE") continuing breach of contract for its failure to dispose of spent nuclear fuel and high-level radioactive waste, the Settlement Agreement provided that Energy Northwest could be reimbursed by the government for its allowable expenses, as defined in the Settlement Agreement, related to DOE's continued failure to accept used nuclear fuel under the Standard Contract Energy Northwest signed with DOE in 1983. The Settlement Agreement also settled the litigation filed by Energy Northwest in the U.S. Court of Federal Claims in July 2011 for damages incurred between September 1, 2006, and June 30, 2012 in the amount of $23.6 million. Energy Northwest received $48.7 million in 2011 under the first action that resulted in a Stipulation for Entry of Final Judgment in Favor of Plaintiff Energy Northwest which covered damages prior to September 1, 2006.

Under the Settlement Agreement, Energy Northwest is required to submit a claim for reimbursement to DOE annually for each year, July 1, 2012 through December 31, 2016. The claim submission deadline is January 31 of the following calendar year. After submission, DOE has a set time to review and request additional information from Energy Northwest. At the end of the review period, Energy Northwest can accept DOE's determination and be paid the amount determined by DOE or Energy Northwest can reject the determination and proceed to binding arbitration.

Under the Settlement Agreement, Energy Northwest submitted its first claim to DOE by the deadline. The first claim covers Fiscal Years 2013 through 2014 (a catch-up claim). Energy Northwest was reimbursed $15,143,888 in September 2015. In early 2016, Energy Northwest submitted its second claim for costs incurred from July 1, 2014 to June 30, 2015. DOE agreed to pay and Energy Northwest accepted the sum of $4,531,664 in full satisfaction of the claim for costs incurred by Energy Northwest for the time period. Payment from the Judgment Fund was received in fall 2016. The third claim for costs incurred between July 1, 2015 and June 30, 2016, was submitted January 31, 2017. Energy Northwest received confirmation that it would receive $7,200,184 in reimbursed costs on June 6, 2017. The reimbursement was received by Energy Northwest on June 26, 2017. In March of 2017, Energy Northwest was able to extend the Settlement Agreement, by addendum, for an annual claims process terminating December 31, 2019. The first claim under the extended Settlement Agreement, covering costs incurred between July 1, 2016 to June 30, 2017, was submitted January 31, 2018. Energy Northwest received reimbursement of $11,139,345 in September 2018. The second claim under the extended Settlement Agreement, covering costs incurred from July 1, 2017 to June 30, 2018, was submitted January 30, 2019. On June 26, 2019, Energy Northwest received confirmation that it would receive $17,832,584 in reimbursed costs. The third claim under the extended Settlement Agreement, covering costs incurred from July 1, 2018 to June 30, 2019, was submitted January 31, 2020. On July 17, 2020, Energy Northwest received $1,178,445 in reimbursed costs. In August of 2020, Energy Northwest was able to extend the Settlement Agreement, by addendum, for an annual claims process terminating December 31, 2022. The first claim under the second Addendum to the Settlement Agreement, covering costs incurred from July 1, 2019 to June 30, 2020 was submitted January 29, 2021. On June 25, 2021 Energy Northwest received $8,488,241 in reimbursed costs. The second claim under the second Addendum to the Settlement Agreement, covering costs incurred from July 1, 2020 to June 30, 2021 was submitted January 28, 2022. On May 10, 2022 Energy Northwest received the determination letter from DOE approving reimbursement of $8,294,982. Payment is expected to be received in July 2022.

### NOTE 11 - Nuclear Fuels

In May 2012, Energy Northwest entered into agreements with three other parties for processing high assay uranium tails. The Program consists of several agreements between the parties involved, entered into as a joint effort between the Department of Energy (DOE), Tennessee Valley Authority (TVA), United States Enrichment Corporation (USEC) and Energy Northwest to enrich approximately 9,082 metric tons (MTU) of Depleted Uranium Hexafluoride (DUF6) with an average assay of 0.44 weight percent U235 (wt%) that will yield approximately 482 MTU of enriched uranium product (EUP) with an average assay of 4.4 wt%.

DOE and Energy Northwest have entered into an agreement for the transfer of the DUF6 to Energy Northwest. The agreement addresses delivery and transfer of title of the DUF6, return of residual DUF6 after enrichment, storage of the EUP, and payment of DOE's costs. The costs for the handling of the DUF6 and storage of the EUP were anticipated to be $5 million or less. As of December 31, 2015, Energy Northwest had removed all EUP stored with DOE to a commercial facility in New Mexico. Energy Northwest had recorded $0.9 million in total charges to the DOE for delivery of the DUF6, storage and loading of the EUP, which is capitalized as cost of the fuel being purchased.

Under the Depleted Uranium Enrichment Program (DUEP), Energy Northwest purchased from USEC all of the Separative Work Units (SWU) contained in the EUP. Upon finalization of the program, Energy Northwest had purchased a total of 481.6 MTU of EUP from USEC at a cost of $687.2 million, which is recorded in nuclear fuel, net of accumulated amortization, as of June 30, 2013. There have been no additional purchases since the conclusion of the program in May of 2013.

Energy Northwest and TVA have entered into an agreement for the sale and purchase of a portion of the SWU and Feed Component of the EUP. The sales under the agreement are expected to total approximately $730 million. The payment for the sixth delivery of 385,000 SWU was received June 1, 2020 for $67.46 million. The payment for the seventh delivery of 480,000 SWU was received August 31, 2021 for $85.92 million. The final sale under this agreement is scheduled to take place between July 2022 and September 2022.

Energy Northwest has a contract with Global Nuclear Fuel - Americas LLC valued at $192.0 million for fuel fabrication services through FY 2027 with an option to extend for two additional reloads through 2031. The delivery of new fuel assemblies coincides with each refueling outage year, with the refueling complete in June 2021 (R-25).

Energy Northwest has a contract with DOE that requires DOE to accept title and dispose of spent nuclear fuel. Although the courts have ruled that DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current waste disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current waste disposal fee to zero. On May 9, 2014, the DOE notified Energy Northwest that the waste disposal fee will remain in effect through May 15, 2014, after which time the fee will be set to zero. Until such time as a new fee structure is in effect, Energy Northwest will not accrue any further costs related to waste disposal fees. When the fuel is placed in the reactor the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. The amount moved to spent fuel for cooling decreased $95.40 million.

The current period operating expense for Columbia was $50.89 million for amortization of fuel used in the reactor. There were no DOE spent fuel disposal charges.

Energy Northwest has an Independent Spent Fuel Storage Installation (ISFSI), which is a temporary dry cask storage facility to be used until DOE completes its plan for a national repository. ISFSI will store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. There were 9 casks issued from inventory in fiscal year 2022. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refueling. The FY 2022 ISFSI loading campaign filled a total of 9 casks. The next ISFSI loading campaign is scheduled for March of 2026 for a total of 10 casks.

**NOTE 12 - Other Post-Employment Benefits**

The following table represents the aggregate OPEB amounts for all plans subject to the requirements of GASB 75 for the year ended June 30, 2022 (in thousands):

| | |
|---|---|
| OPEB Liabilities | $ 29,571 |
| Deferred Outflows of Resources | 1,343 |
| OPEB Expense | 1,660 |

The Agency provides to its retirees employer subsidies for postemployment medical insurance benefits (OPEB) provided through the Public Employees Benefits Board (PEBB). The actual medical costs are paid through annual fees and premiums to the PEBB.

**General Information about the OPEB Plan**

**Plan Description**

The PEBB was created within the Washington State Health Care Authority to administer medical, dental and life insurance plans for public employees and retirees and their dependents as a single employer plan. Agency employees who end public employment are eligible to continue PEBB insurance coverage as a retiree if they retire under the public employees' retirement system and are vested in that system.

**Benefits Provided**

The Washington State Health Care Authority (HCA) administers PEBB plan benefits. For medical insurance coverage, the HCA has two claims pools: one covering employees and non-Medicare eligible retirees, and the other covering retirees enrolled in Medicare Parts A and B. Each participating employer pays a portion of the premiums for active employees. For retirees, participating employers provide two different subsidies: an explicit subsidy and an implicit subsidy.

The explicit subsidies are monthly amounts paid per post-65 retiree and spouse. As of the valuation date of June 30, 2021, the explicit subsidy for post-65 retirees and spouses is the lesser of $183 or 50% of the monthly premiums. The retirees and spouses currently pay the premium minus $183 when the premium is over $366 per month and pay half the premium when the premium is lower than $366.

The implicit medical subsidy is the difference between the total cost of medical benefits and the premiums. For pre-65 retirees and spouses, the retiree pays the full premium amount, but that amount is based on a pool that includes active employees. Active employees will tend to be younger and healthier than retirees on average, and therefore can be expected to have lower average health costs. For post-65 retirees and spouses, the retiree does not pay the full premium due to the subsidy discussed above.

### Employees Covered by Benefit Terms

At June 30, 2021 (measurement date), the following employees were covered by the benefit terms:

| | |
|---|---|
| Inactive employees or beneficiaries currently receiving benefit payments | 465 |
| Inactive employees entitled to but not yet receiving benefit payments | - |
| Active employees | 918 |

### Funding Policy

The plan is funded on a pay-as-you-go basis and there are no assets accumulating in a qualifying trust.

### Contributions

The OPEB relationship between PEBB employers and their employees and retirees is not formalized in a contract or plan document. Rather, the benefits are provided in accordance with a substantive plan. A substantive plan is one in which the plan terms are understood by the employers and plan members. This understanding is based on communications between the employers and plan members and the historical pattern of practice with regard to the sharing of benefit costs.

### Total OPEB Liability

The Agency's total OPEB liability was measured as of June 30, 2021 and was determined by an actuarial valuation dated June 30, 2020.

The total OPEB liability in the June 30, 2020 actuarial valuation was determined using the following actuarial assumptions and other inputs:

| | |
|---|---|
| Methodolgy: | |
| Actuarial Cost Method | Entry Age Normal (Level Percent of Salary) |
| Assumptions: | |
| Discount Rate - Based on Bond Buyer General Obligation 20-Bond Municipal Index: | 2.25% |
| Beginning of Measurement Year | 2.25% |
| End of Measurement Year | 2.25% |
| Projected Salary Changes | 3.50% |
| | Plus Merit-Based Increases |
| Medical Care Trend | Actual for the first year, then 6.4% decreasing .10% per year down to 5.0% |
| Actuarial Assumptions - Based on experience study conducted in 2020 using Public Employees' Retirement System (PERS) experience from 2013-2018 | |
| Mortality Assumptions - PubG.H-2010 mortality tables adjusted for future mortality improvements using the MP-2017 fully generational improvement scale. | |
| Inflation Rate | 2.00% |
| Post Retirement Participation Percentage - 100% of active employees currently electing coverage. Upon exhaustion of HRA VEBA funds, 50% are assumed to self-pay premiums. 3% of covered retirees are assumed to let their coverage lapse each year. | |
| Percentage with Spouse Coverage | 70.00% |

### Changes in the Total OPEB Liability

| | | |
|---|---|---|
| Balance - July 1 | $ | 29,254 |
| Service Cost | | 1,006 |
| Interest | | 654 |
| Benefit Payments | | (1,343) |
| Total | $ | 29,571 |

Sensitivity of the Total OPEB Liability to Changes in the Healthcare Cost Trend Rate and Discount Rate.

The following presents the total OPEB liability of the Agency calculated using a discount rate and healthcare cost trend rates that are 1-percentage point lower or 1-percentage-point higher than the current discount rate and health care cost trend rates (in thousands):

| | 1% Decrease | Current Rate | 1% Increase |
|---|---|---|---|
| Discount Rate | $ 33,810 | $ 29,571 | $ 26,099 |
| Healthcare Cost Trend Rate | 25,509 | 29,571 | 34,722 |

OPEB Expense and Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB

The Agency recognized OPEB expense for the years ended December 31 as follows (in thousands):

| | | |
|---|---|---|
| Service Cost | $ | 1,006 |
| Interest Cost | | 654 |
| Total | $ | 1,660 |

At December 31, the Agency reported deferred outflows of resources and deferred inflows of resources related to OPEB from the following sources (in thousands):

| | | |
|---|---|---|
| Deferred Outflows of Resources | | |
| Contributions Subsequent to the Measurement Date | $ | 1,343 |

Deferred outflows of resources resulting from payments subsequent to the measurement date will be recognized as a reduction of the total OPEB liability in the following year.

## NOTE 13 - Leases

### Lessee:

Energy Northwest (EN) under the following business units Nine Canyon Wind Project, Business Development, Internal Service Fund, Packwood Lake Hydroelectric Project, Columbia Generating Station, and Nuclear Project No. 1, have several leasing arrangements, summarized below:

The Nine Canyon Wind Project entered into a lease agreement to lease land space for three-hundred eighteen months beginning July 2021. The lease terminates December 2047. Under the terms of the lease, EN pays an annual base fee of $42,400, with an increase scheduled in fiscal year 2023. The base fee will follow the fixed rent schedule outlined in the lease agreement. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $15 during the fiscal year towards those variable costs. On June 30, 2022, EN recognized a right to use asset of $807,472 and a lease liability of $796,738. During the fiscal year, EN recorded $31,666 in amortization expense and $20,420 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Business Development fund entered into a sublease agreement to lease land space for forty-eight months beginning July 2021. The lease terminates August 2025. Under the terms of the lease, EN pays an annual base fee of $7,500, with a 3.0% increase for the immediately preceding Term or extension period. On June 30, 2022, EN recognized a right to use asset of $130,287 and a lease liability of $129,004. During the fiscal year, EN recorded $5,624 in amortization expense and $3,336 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Internal Service Fund entered into a lease agreement to lease office space for thirteen months beginning July 2021. The lease terminates July 2022. Under the terms of the lease, EN paid a monthly base fee of $3,273 for July 2021 and beginning in August 2021, EN pays a monthly base fee of $3,336 through the end of the lease term. On June 30, 2022, EN recognized a right to use asset of $3,289 and a lease liability of $3,329. During the fiscal year, EN recorded $39,463 in amortization expense and $554 in interest expense for the right to use the office space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Packwood Hydroelectric Project entered into a lease agreement to lease equipment for thirty months beginning July 2021. The lease terminates January 2024. Under the terms of the lease, EN pays a monthly base fee of $917. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $50 during the fiscal year towards those variable costs. On June 30, 2022, EN recognized a right to use asset of $16,640 and a lease liability of $17,046. During the fiscal year, EN recorded $10,879 in amortization expense and $561 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Nuclear Project No.1 entered into a lease agreement to lease land space for three-hundred sixty-six months beginning July 2021. The lease terminates December 2052. Under the terms of the lease, EN pays an annual base fee of $60,000, with an increase every 5 years during the Initial Term of the lease. On June 30, 2022, EN recognized a right to use asset of $1,261,836 and a lease liability of $1,243,897. During the fiscal year, EN recorded $42,061 in amortization expense and $31,881 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Nuclear Project No.1 entered into a lease agreement to lease a building for twenty-four months beginning July 2021. The lease terminates June 2023. Under the terms of the lease, EN paid a monthly base fee of $2,943 for the first seven months of the fiscal year. In February 2022, EN pays a monthly base rate of $3,456 through the end of the lease Term. On June 30, 2022, EN recognized a right to use asset of $37,035 and a lease liability of $38,531. During the fiscal year, EN recorded $37,035 in amortization expense and $1,420 in interest expense for the right to use the building space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease land space for three-hundred seventy-two months beginning July 2021. The lease terminates December 2052. Under the terms of the lease, EN pays an annual base fee of $65,000. On June 30, 2022, EN recognized a right to use asset of $1,019,203 and a lease liability of $1,006,470. During the fiscal year, EN recorded $52,267 in amortization expense and $25,795 in interest expense for the right to use the land space. EN used an incremental discount rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for eighty-six months beginning July 2021. The lease terminates September 2028.

Under the terms of the lease, EN pays a monthly base fee of $20,012. On June 30, 2022, EN recognized a right to use asset of $1,326,316 and a lease liability of $1,335,061. During the fiscal year, EN recorded $214,981 in amortization expense and $36,630 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for one-hundred eleven months beginning November 2021. The lease terminates February 2031. Under the terms of the lease, EN pays a monthly base fee of $20,790, which is a fixed price for the duration of the performance period. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $3,479 during the fiscal year towards those variable costs. On June 30, 2022, EN recognized a right to use asset of $1,842,341 and a lease liability of $1,936,283. During the fiscal year, EN recorded $212,578 in amortization expense and $51,641 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

**Nine Canyon Wind Project**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 22 | $ 20 |
| 2024 | 22 | 19 |
| 2025 | 23 | 19 |
| 2026 | 24 | 18 |
| 2027 | 24 | 18 |
| 2028-2032 | 131 | 78 |
| 2033-2037 | 149 | 60 |
| 2038-2042 | 169 | 39 |
| 2043-2047 | 192 | 15 |
| 2048-2052 | 41 | - |
| Total | $ 797 | $ 285 |

**Business Development Fund**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 4 | $ 3 |
| 2024 | 4 | 3 |
| 2025 | 4 | 3 |
| 2026 | 5 | 3 |
| 2027 | 5 | 3 |
| 2028-2032 | 25 | 12 |
| 2033-2037 | 28 | 9 |
| 2038-2042 | 32 | 5 |
| 2043-2047 | 21 | 1 |
| Total | $ 129 | $ 41 |

**Internal Service Fund**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 3 | $ - |
| 2024 | - | - |
| 2025 | - | - |
| 2026 | - | - |
| Total | $ 3 | $ - |

**Packwood Hydroelectric Project**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 11 | $ - |
| 2024 | 6 | - |
| 2025 | - | - |
| 2026 | - | - |
| Total | $ 17 | $ - |

**Nuclear Project No.1**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 67 | $ 32 |
| 2024 | 29 | 31 |
| 2025 | 29 | 30 |
| 2026 | 30 | 29 |
| 2027 | 31 | 28 |
| 2028-2032 | 167 | 128 |
| 2033-2037 | 190 | 105 |
| 2038-2042 | 216 | 79 |
| 2043-2047 | 245 | 49 |
| 2048-2052 | 278 | 15 |
| Total | $ 1,282 | $ 525 |

**Columbia Generating Station**

| Fiscal Year Ended June 30 | Principal | Interest |
|---|---|---|
| 2023 | $ 739 | $ 127 |
| 2024 | 758 | 108 |
| 2025 | 778 | 88 |
| 2026 | 592 | 70 |
| 2027 | 606 | 55 |
| 2028-2032 | 1,343 | 129 |
| 2033-2037 | 265 | 53 |
| 2038-2042 | 301 | 16 |
| Total | $ 5,382 | $ 646 |

**Amortization Expenses** (Dollars in thousands)

| | Lessee activities | Balance at July 1, 2021 | Additions | Deletions | Balance at June 30, 2022 |
|---|---|---|---|---|---|
| **Nine Canyon Wind Project** Right to use assets | Office Space | $ - | $ - | $ - | $ - |
| | Land | 839 | - | - | 839 |
| | Equipment | - | - | - | - |
| | Building Space | - | - | - | - |
| Nine Canyon Wind Project Totals | | $ 839 | $ - | $ - | $ 839 |
| **Business Development Fund** Right to use assets | Office Space | $ - | $ - | $ - | $ - |
| | Land | 136 | - | - | 136 |
| | Equipment | - | - | - | - |
| | Building Space | - | - | - | - |
| Business Development Fund Totals | | $ 136 | $ - | $ - | $ 136 |
| **Internal Service Fund** Right to use assets | Office Space | $ 43 | $ - | $ - | $ 43 |
| | Land | - | - | - | - |
| | Equipment | - | - | - | - |
| | Building Space | - | - | - | - |
| Internal Service Fund Totals | | $ 43 | $ - | $ - | $ 43 |
| **Packwood Lake Hydroelectric Project** Right to use assets | Office Space | $ - | $ - | $ - | $ - |
| | Land | - | - | - | - |
| | Equipment | 27 | - | - | 27 |
| | Building Space | - | - | - | - |
| Packwood Project Totals | | $ 27 | $ - | $ - | $ 27 |
| **Nuclear Project No.1** Right to use assets | Office Space | $ - | $ - | $ - | $ - |
| | Land | 1,304 | - | - | 1,304 |
| | Equipment | - | - | - | - |
| | Building Space | - | 74 | - | 74 |
| Nuclear Project No.1 Totals | | $ 1,304 | $ 74 | $ - | $ 1,378 |
| **Columbia Generating Station** Right to use assets | Office Space | $ - | $ - | $ - | $ - |
| | Land | 1,071 | - | - | 1,071 |
| | Equipment | 4,996 | - | - | 4,996 |
| | Building Space | - | - | - | - |
| Columbia Generating Station Totals | | $ 6,067 | $ - | $ - | $ 6,067 |

## Lessor:

Energy Northwest owns a multipurpose building in the City of Richland, Benton County, Washington known as the Applied Process Engineering Laboratory (APEL) which provides leased space of laboratory, validation testing, development facilities and associated offices for research and development. There are two lease agreements associated with the APEL building.

The first agreement was entered into in February of 2021 with a 3-year lease term. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, the lessee must remove any alterations and restore the premises to its original condition unless the lessor agrees to leaving the improvements in place. During the fiscal year, Energy Northwest recognized (in thousands) $53 in lease revenue and $3 in interest income related to this agreement. On June 30, 2022, Energy Northwest recorded $89 in lease receivables and $87 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 2.57%, based on the 2020 bond interest rate.

The second agreement was entered into in May of 2021. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, the lessee has the right to remove any alterations and shall restore the premises to its original condition. During the fiscal year, Energy Northwest recognized (in thousands) $187 in lease revenue and $4 in interest income related to this agreement. On June 30, 2022, Energy Northwest recorded $65 in lease receivables and $64 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 2.57%, based on the 2020 bond interest rate.

Energy Northwest leases a portion of the office space in the building known as the Multi-Purpose Facility in the City of Richland, Benton County, Washington. This agreement was entered into in July of 2019 with a 4-year lease term and contained 3 two-year option periods which Energy Northwest believes is reasonably certain to renew. Contract rent will increase annually based on the Consumers Price Index with a 3% cap. During the fiscal year, Energy Northwest recognized (in thousands) $360 in lease revenue and $69 in interest income related to this agreement. On June 30, 2022, Energy Northwest recorded $2,239 in lease receivables and $2,212 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 2.57%, based on the 2020 bond interest rate.

Energy Northwest maintains a lease for the plot of land from the Department of Energy-Richland Operations located in Benton County, Washington. This agreement leases a portion of the property consisting of a room/cabinet space of approximately 92 square feet and space on the structure and such easements as are necessary for antennas. This agreement was entered into in June of 2019 with a 5-year lease term and contained 5 five-year option periods which Energy Northwest believes is reasonably certain to renew. Contract rent will increase 2.5% at the end of the initial lease term and 9% at each 5-year option renewal. During the fiscal year, Energy Northwest recognized (in thousands) $17 in lease revenue and $12 in interest income related to this agreement. On June 30, 2022, Energy Northwest recorded $475 in lease receivables and $470 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 2.57%, based on the 2020 bond interest rate.

**Lease Receivable Activity** (Dollars in thousands)

| | Balance at July 1, 2021 | Additions | Receipts | Balance at June 30, 2022 |
|---|---|---|---|---|
| **Business Development** | | | | |
| Rack Space | $ 488 | $ - | $ (13) | $ 475 |
| **Columbia** | | | | |
| Building | $ 4,325 | $ - | $ (1,932) | $ 2,393 |
| Total Lease Receivable | $ 4,813 | $ - | $ (1,945) | $ 2,868 |

Remaining amounts to be received associated with these leases are as follows:

**Lease Revenue** (Dollars in thousands)

| | Columbia | | Business Development | |
|---|---|---|---|---|
| Fiscal Year Ended June 30 | Lease Revenue | Lease Interest | Lease Revenue | Lease Interest |
| 2023 | $ 435 | $ 55 | $ 17 | $ 12 |
| 2024 | 349 | 46 | 17 | 12 |
| 2025 | 316 | 38 | 17 | 11 |
| 2026 | 316 | 30 | 17 | 11 |
| 2027 | 316 | 21 | 17 | 11 |
| 2028-2033 | 632 | 17 | 105 | 56 |
| 2034-2039 | - | - | 105 | 41 |
| 2040-2045 | - | - | 105 | 24 |
| 2046-2049 | - | - | 69 | 5 |
| Total | $ 2,364 | $ 207 | $ 471 | $ 183 |

## Schedule of the Energy Northwest's Proportionate Share of the Net Pension Liability (Dollars in thousands)

**PERS 1**

| Measurement Date Ended June 30 | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|---|---|---|---|
| Proportion of the net pension liability (asset) | 0.99% | 0.89% | 1.02% | 1.08% | 1.13% | 1.08% | 1.24% | 1.22% | 1.19% |
| Proportionate share of the net pension liability (asset) | $ 12,128 | $ 31,376 | $ 39,358 | $ 48,192 | $ 53,781 | $ 58,147 | $ 65,005 | $ 61,291 | $ 71,094 |
| Covered-employee payroll | 146,520 | 134,853 | 143,601 | 143,282 | 142,483 | 128,944 | 154,431 | 144,597 | 140,409 |
| Proportionate share of the net pension liability (asset) as a percentage of its covered-employee payroll | 8.28% | 23.27% | 27.41% | 33.63% | 37.75% | 45.09% | 42.09% | 42.39% | 50.63% |
| Plan fiduciary net position as a percentage of the total pension liability | 88.74% | 68.64% | 67.12% | 63.22% | 61.24% | 57.03% | 59.10% | 61.19% | 55.70% |

**PERS 2/3**

| Measurement Date Ended June 30 | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|---|---|---|---|
| Proportion of the net pension liability (asset) | 1.28% | 1.16% | 1.32% | 1.38% | 1.45% | 1.38% | 1.60% | 1.55% | 1.55% |
| Proportionate share of the net pension liability (asset) | $ (127,200) | $ 14,795 | $ 12,831 | $ 23,584 | $ 50,411 | $ 69,510 | $ 57,017 | $ 31,410 | $ 66,351 |
| Covered-employee payroll | 146,520 | 134,852 | 143,502 | 143,015 | 142,140 | 128,634 | 154,080 | 144,158 | 139,637 |
| Proportionate share of the net pension liability (asset) as a percentage of its covered-employee payroll | -86.81% | 10.97% | 8.94% | 16.49% | 35.47% | 54.04% | 37.00% | 21.79% | 47.52% |
| Plan fiduciary net position as a percentage of the total pension liability | 120.29% | 97.22% | 97.77% | 95.77% | 90.97% | 85.82% | 89.20% | 93.29% | 84.60% |

## Schedule of Energy Northwest's Contributions (Dollars in thousands)

**PERS 1**

| Fiscal Year Ended June 30 | 2022 | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| Contractually Required Contribution | $ 5,619 | $ 7,397 | $ 6,441 | $ 7,339 | $ 7,213 | $ 6,818 | $ 6,141 | $ 5,711 | $ 5,385 | $ 3,078 |
| Contributions in Relation to the Contractually Required Contribution Subtotal | (5,619) | (7,397) | (6,441) | (7,339) | (7,213) | (6,818) | (6,141) | (5,711) | (5,385) | (3,078) |
| Contribution Deficiency (Excess) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Covered-Employee Payroll | $ 150,964 | $ 152,720 | $ 134,853 | $ 143,601 | $ 143,282 | $ 142,483 | $ 128,944 | $ 154,431 | $ 144,597 | $ 140,409 |
| Contributions as a Percentage of Covered Employee Payroll | 3.72% | 4.84% | 4.78% | 5.11% | 5.03% | 4.79% | 4.76% | 3.70% | 3.72% | 2.19% |

**PERS 2/3**

| Fiscal year Ended June 30 | 2022 | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| Contractually Required Contribution | $ 9,627 | $ 12,095 | $ 10,657 | $ 10,789 | $ 10,658 | $ 8,862 | $ 8,200 | $ 7,108 | $ 6,564 | $ 6,020 |
| Contributions in Relation to the Contractually Required Contribution | (9,627) | (12,095) | (10,657) | (10,789) | (10,658) | (8,862) | (8,200) | (7,108) | (6,564) | (6,020) |
| Contribution Deficiency (Excess) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Covered-Employee Payroll | $ 150,964 | $ 152,720 | $ 134,852 | $ 143,502 | $ 143,015 | $ 142,140 | $ 128,634 | $ 154,080 | $ 144,158 | $ 139,637 |
| Contributions as a Percentage of Covered Employee Payroll | 6.38% | 7.92% | 7.90% | 7.52% | 7.45% | 6.23% | 6.37% | 4.61% | 4.55% | 4.31% |

**Notes to Schedules**

- DRS allocates certain portion of contributions from PERS Plan 2/3 to PERS Plan 1 in order to fund its unfunded actuarially accrued liability (UAAL).
- There were no changes in actuarial as assumptions between the valuation date of June 30, 2013 and the measurement date of June 30, 2014.
- There were no changes in actuarial as assumptions between the valuation date of June 30, 2014 and the measurement date of June 30, 2015.
- There were no changes in actuarial as assumptions between the valuation date of June 30, 2015 and the measurement date of June 30, 2016.
- There were no changes in actuarial as assumptions between the valuation date of June 30, 2016 and the measurement date of June 30, 2017.
- There were no changes in actuarial as assumptions between the valuation date of June 30, 2017 and the measurement date of June 30, 2018.
- There were changes in actuarial as assumptions between the valuation date of June 30, 2018 and the measurement date of June 30, 2019.
    - Lowered the valuation interest rate from 7.70% to 7.50% for all plans.
    - Lowered the assumed general salary growth from 3.75% to 3.50% for all plans.
    - Lowered assumed inflation from 3.00% to 2.75% for all plans.
    - Lowered assumed investment rate of return from 7.50% to 7.40% for all plans.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2019 and the measurement date of June 30, 2020.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2020 and the measurement date of June 30, 2021.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2020 and the measurement date of June 30, 2022.

## Schedule of the Energy Northwest's Changes in the Total OPEB Liability and Related Ratios (Dollars in thousands)

| | PERS 1 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Measurement Date Ended June 30 | 2021 | 2020 | 2019 | 2018 | 2017 | 2016 | 2015 | 2014 | 2013 |
| Total OPEB Liability - Beginning | $ 29,254 | $ 28,850 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Service Cost | 1,006 | 1,006 | - | - | - | - | - | - | - |
| Interest | 654 | 646 | - | - | - | - | - | - | - |
| Changes in Experience and Data Assumptions | - | - | - | - | - | - | - | - | - |
| Changes in Benefit Terms | - | - | - | - | - | - | - | - | - |
| Benefit Payments | (1,343) | (1,248) | - | - | - | - | - | - | - |
| Total OPEB Liability - Ending | $ 29,571 | $ 29,254 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Covered-Employee Payroll | $ 102,720 | $ 113,576 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Total OPEB Liability as a % of Covered-Employee Payroll | 28.79% | 25.76% | 0.00% | 0.00% | - 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

**Notes to Schedules**

No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB 75.

* Until a full 10-year trend is compiled, only information for those years available is presented.

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL
FOR THE SERIES 2023-A BONDS

Energy Northwest

J.P. Morgan Securities LLC

Wells Fargo Bank, National Association

BofA Securities, Inc.

Citigroup Global Markets Inc.

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$16,435,000/$416,180,000/$74,200,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] Refunding Bonds, Series 2023-A (the "2023-A Bonds"). The 2023-A Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 22, 2023 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

The 2023-A Bonds are subject to redemption prior to their stated maturities as provided in the Bond Resolutions. The 2023-A Bonds rank equally as to security and payment with all other Parity Debt.

Regarding questions of fact material to our opinion, we have relied on representations of Energy Northwest in the Bond Resolutions and in the certified proceedings and on other certifications of public officials and others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

1. Energy Northwest is a municipal corporation and joint operating agency, duly created and existing under the laws of the State, including particularly the Act, having the right and power under the Act to acquire, construct, own and operate the Project, adopt the Bond Resolutions, issue the 2023-A Bonds and apply the proceeds of the 2023-A Bonds in accordance with the Supplemental Resolution.

2. The Bond Resolutions have been duly and lawfully adopted by Energy Northwest, are in full force and effect, are valid and binding upon Energy Northwest and are enforceable in accordance with their terms. Energy Northwest's covenants in the Bond Resolutions to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the 2023-A Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2023-A Bonds have been duly and validly authorized and issued under the Act and the Bond Resolutions and constitute valid and binding special revenue obligations of Energy Northwest, enforceable in accordance with their terms and the terms of the Bond Resolutions. The 2023-A Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2023-A Bonds are not a debt of the State or any political subdivision thereof (other than Energy Northwest), and neither the State nor any other political subdivision of the State is liable thereon.

The opinions above are qualified to the extent that the enforcement of the rights and remedies of the owners of the 2023-A Bonds may be limited by laws relating to bankruptcy, reorganization, insolvency, moratorium or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and by the exercise of judicial discretion, and we express no opinion regarding the enforceability of provisions in the Bond Resolutions that provide for rights of indemnification.

This opinion is given as of the date hereof, and we assume no obligation to update, revise or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

Very truly yours,

FOSTER GARVEY P.C.

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PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL
FOR THE SERIES 2023-A BONDS

Energy Northwest

J.P. Morgan Securities LLC

Wells Fargo Bank, National Association

BofA Securities, Inc.

Citigroup Global Markets Inc.

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$16,435,000/$416,180,000/$74,200,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] Refunding Bonds, Series 2023-A (the "2023-A Bonds"). The 2023-A Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 22, 2023 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

In connection with the issuance of the 2023-A Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/2/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/2/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement") (collectively the "Agreements"), by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State and such statutes and regulations as we deemed relevant to this opinion, including particularly the Act;

(b) The Constitution of the United States of America and such statutes and regulations as we deemed relevant to this opinion, including particularly the Bonneville Project Act of 1937, as amended (the "Bonneville Act"), the Flood Control Act of 1944, Public Law 88-552, as amended, the Federal Columbia River Transmission System Act of 1974, as amended, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, as amended;

(c) Certified copies of the Electric Revenue Bond Resolution and the Supplemental Resolution;

(d) Certified copies of the Net Billing Agreements and the Assignment Agreement;

(e) The Certificate of the General Counsel of Energy Northwest, dated the date hereof, certifying that (i) neither Energy Northwest nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) The Certificate of the Administrator, dated the date hereof, certifying that (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(g) Certified copies of the proceedings of Energy Northwest authorizing the execution and delivery of the Net Billing Agreements and the Assignment Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, inter alia, (i) the office of Administrator was duly established and is validly existing under the Bonneville Act, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the Assignment Agreement, and (iii) each of the Net Billing Agreements and the Assignment Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System, et al.*, 752 F.2d 1423 (9th Cir. 1985), *cert. denied*, 474 U.S. 1055 (1986) ("Springfield"); and

(j) Such other documents, agreements, proceedings, pleadings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon and based on the assumptions, exceptions and conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Project 1 consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville and the Participants currently obligated under the Net Billing Agreements, enforceable against such parties in accordance with its terms.

The foregoing opinion is subject to the following limitations, qualifications, exceptions, and assumptions:

(A) In rendering the opinion as to the enforceability of the Net Billing Agreements as to the Participants, we have assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations as therein stated, under the Net Billing Agreements and Assignment Agreement. The assumption in the preceding sentence does not limit or affect our opinion as to the enforceability of the Net Billing Agreements and Assignment Agreement against Bonneville.

(B) The enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

(C) In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the Office of General Counsel of Energy Northwest and the Administrator referred to above in paragraphs (e) and (f); and (3)(A) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (B) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreement to which such Participant is a party and that all assignments of any Participant's obligations under the Net Billing Agreements were properly done, and (C) with respect to the Participant's obligations under the Net Billing Agreements, no violation of or conflict with the provisions of applicable law, and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

(D) The opinions expressed herein are qualified to the extent that the characterization of, and the enforceability of any rights or remedies in, the Agreements may be limited by concepts of materiality, reasonableness, good faith and fair dealing, and rules governing specific performance, injunctive relief, marshalling, subrogation and other equitable remedies, regardless of whether raised in a court of law or otherwise. The opinions expressed herein are based on an analysis of existing laws (including, but not limited to, the law that provides that Bonneville may make expenditures from the Bonneville Fund which have been included in Bonneville's budget submitted to Congress without further appropriation or fiscal year limitation), 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 the date hereof.

(E) We express no opinion with respect to any provision for a remedy which is determined to be in the nature of a penalty, forfeiture or punitive damages, or which would provide the claimant with a duplication of damage awards or cumulative remedy, or which waives the applicability of any rule requiring an election of remedies. We express no opinion with respect to the obligation of Bonneville or any Participant to pay any debt or other obligation related to the Project on an accelerated basis.

(F) Our opinions are subject to the context rule of interpretation of contracts, which provides that even though terms of a contract may be unambiguous, courts may admit extrinsic evidence to interpret the contract.

This letter has been prepared solely for your use in connection with the transactions contemplated by the Agreements and should not be quoted in whole or in part or otherwise be referred to nor be relied upon by, filed with or furnished to, any governmental agency or other person or entity (other than your legal and professional advisors) without the prior consent of this firm. No attorney-client relationship has existed or exists between our firm and Bonneville, the Participants or the Underwriters with respect to the subject matter hereof or by virtue of this opinion. This letter opinion speaks as of its date and we do not hereby undertake to update this letter opinion. The opinions expressed in this letter are limited to the matters set forth in this letter, and no other opinions should be inferred beyond the matters expressly stated.

Very truly yours,

FOSTER GARVEY P.C.

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL
FOR THE SERIES 2023-A BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$16,435,000 Project 1 Electric Revenue Refunding Bonds, Series 2023-A
$416,180,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A
$74,200,000 Project 3 Electric Revenue Refunding Bonds, Series 2023-A

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $16,435,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2023-A (the "Project 1 Series 2023-A Bonds"), $416,180,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2023-A (the "Columbia Series 2023-A Bonds") and $74,200,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2023-A (the "Project 3 Series 2023-A Bonds," and together with the Project 1 Series 2023-A Bonds and the Columbia Series 2023-A Bonds, the "Series 2023-A Bonds").

The Project 1 2023-A Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), and Resolution No. 835, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 22, 2023 (the "Project 1 Resolution"). The Project 1 Resolution provides that the Project 1 2023-A Bonds are being issued for the purpose of paying (directly or indirectly through repayment of a bond anticipation note) a portion of the interest due on certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Project 1 2023-A Bonds.

The Columbia 2023-A Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted by Energy Northwest on October 27, 1997, as amended and supplemented, and a supplemental resolution adopted on March 22, 2023 (the "Columbia Resolution"). The Columbia Resolution provides that the Columbia 2023-A Bonds are being issued for the purpose of paying costs of capital improvements to the Columbia Generating Station, refunding certain outstanding bonds issued by Energy Northwest, paying (directly or indirectly through repayment of a bond anticipation note) a portion of the interest due on certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Columbia 2023-A Bonds.

The Project 3 2023-A Bonds are being issued pursuant to the Act, and Resolution No. 838, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 22, 2023 (the "Project 3 Resolution"). The Project 3 Resolution provides that the Project 3 2023-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest, paying (directly or indirectly through repayment of a bond anticipation note) a portion of the interest due on certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Project 3 2023-A Bonds.

In such connection, we have reviewed certified copies of the Resolutions; the Tax Matters Certificate executed and delivered by Energy Northwest on the date hereof and the Tax Matters Certificate executed and delivered by the Bonneville Power Administration on the date hereof (collectively, the "Tax Certificates"); the opinions of Foster Garvey P.C., as Bond Counsel, dated the date hereof (the "Bond Counsel Opinions"); additional certificates of Energy Northwest, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein. We also have reviewed the opinions of bond counsel to Energy Northwest delivered in connection with the issuance of notes and bonds refunded directly or indirectly by the Series 2023-A Bonds (the "Prior Bond Counsel Opinions"), each of which speaks as of its dated date.

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 2023-A 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 2023-A 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 2023-A 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 provided to us and the due and legal execution and delivery thereof by, and validity against, all parties. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the fifth paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolutions and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Series 2023-A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2023-A Bonds, the Resolutions and the Tax Certificates 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 bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated May 2, 2023, relating to the Series 2023-A Bonds, or other offering material relating to the Series 2023-A Bonds and express no opinion or view with respect thereto.

We have relied with your consent on the Bond Counsel Opinions with respect to the validity of the Series 2023-A Bonds and with respect to the due authorization and issuance of the Series 2023-A Bonds. With your consent, we also have relied on Prior Bond Counsel Opinions with respect to the validity and the due authorization and issuance of notes and bonds refunded directly or indirectly by the Series 2023-A Bonds.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. Interest on the Series 2023-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code").

2. Interest on the Series 2023-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. We observe that, for tax years beginning after December 31, 2022, interest on the Series 2023-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax.

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 2023-A Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

**ENERGY NORTHWEST**
**PARTICIPANT UTILITY SHARE OF**
**FISCAL YEAR 2023 BUDGETS**

| | Participant Utility | Project 1 Share | Columbia Share | Project 3 Share |
|---|---|---|---|---|
| | City of Albion, Idaho | 0.004 | 0.016 | 0.003 |
| | City of Bandon, Oregon | 0.166 | 0.263 | 0.144 |
| * | Public Utility District No. 1 of Benton County, Washington | 4.965 | 5.350 | 4.295 |
| | Benton Rural Electric Association, Washington | 0.308 | 0.666 | 0.645 |
| | Big Bend Electric Cooperative, Inc., Washington | 0.179 | 1.610 | 0.374 |
| | Blachly-Lane County Cooperative Electric Association, Oregon | 0.234 | 0.272 | 0.491 |
| | Blaine City Light, Washington | 0.109 | 0.185 | 0.101 |
| | City of Bonners Ferry, Idaho, Electric Department | 0.115 | 0.182 | 0.099 |
| | City of Burley, Idaho, Electric | 0.179 | 0.694 | 0.155 |
| | Canby Utility Board, Oregon | 0.296 | 0.090 | 0.256 |
| | City of Cascade Locks, Oregon | 0.074 | 0.054 | 0.064 |
| | Central Electric Cooperative, Inc., Oregon | 0.462 | 0.586 | 0.966 |
| | Central Lincoln People's Utility District, Oregon | 4.169 | 4.017 | 3.607 |
| * | City of Centralia, Washington, Electric Light Department | 0.298 | 0.739 | 0.258 |
| * | Public Utility District No. 1 of Chelan County, Washington | 0.501 | | 0.433 |
| | City of Cheney, Washington, Light Department | 0.511 | 0.539 | 0.442 |
| * | Public Utility District No. 1 of Clallam County, Washington | 1.157 | 1.769 | 1.001 |
| * | Public Utility District No. 1 of Clark County, Washington | 14.305 | 6.151 | 13.633 |
| | Clatskanie People's Utility District, Oregon | 0.418 | 1.996 | 0.530 |
| | Clearwater Power Company, Idaho | 0.274 | 0.775 | 0.573 |
| | Columbia Basin Electric Cooperative, Inc., Oregon | 0.161 | 0.673 | 0.338 |
| | Columbia Power Cooperative Association, Oregon | 0.042 | 0.143 | 0.088 |
| | Columbia Rural Electric Association, Inc., Washington | 0.621 | 0.761 | 1.298 |
| | Consolidated Irrigation District No. 19, Washington | 0.005 | | 0.005 |
| | Consumers Power, Inc., Oregon | 1.068 | 0.453 | 2.242 |
| | Coos-Curry Electric Cooperative, Inc., Oregon | 0.232 | 1.634 | 0.781 |
| | Town of Coulee Dam, Washington, Light Department | 0.048 | 0.137 | 0.041 |
| | Public Utility District No. 1 of Cowlitz County, Washington | 7.379 | 5.525 | 3.461 |
| | City of Declo, Idaho | 0.026 | 0.019 | 0.023 |
| * | Public Utility District No. 1 of Douglas County, Washington | 0.044 | | 0.049 |
| | Douglas Electric Cooperative, Inc., Oregon | 0.331 | 0.363 | 0.692 |
| | City of Drain, Oregon, Light and Power | 0.096 | 0.218 | 0.083 |
| | East End Mutual Electric Company, Ltd., Idaho | 0.011 | 0.033 | 0.023 |
| | Town of Eatonville, Washington | 0.010 | | |
| | City of Ellensburg, Washington | 0.780 | 1.028 | 0.675 |
| | Elmhurst Mutual Power and Light Co., Washington | 0.170 | | |
| | Eugene Water & Electric Board, Oregon | 0.061 | | |
| | Fall River Rural Electric Cooperative, Inc., Idaho | 0.188 | 0.409 | 0.393 |
| | Farmers Electric Co., Idaho | 0.005 | 0.041 | 0.011 |
| * | Public Utility District No. 1 of Ferry County, Washington | 0.105 | 0.171 | 0.091 |
| | City of Fircrest, Washington | 0.423 | | |
| | Flathead Electric Cooperative, Inc., Montana | 0.123 | 0.370 | 0.257 |

* Energy Northwest members.

| | Participant Utility | Project 1 Share | Columbia Share | Project 3 Share |
|---|---|---|---|---|
| | City of Forest Grove, Oregon, Light and Power Department | 0.470 | 0.181 | 0.091 |
| * | Public Utility District No. 1 of Franklin County, Washington | 1.330 | 2.370 | 1.151 |
| | Glacier Electric Cooperative, Inc., Montana | 0.098 | | |
| * | Public Utility District No. 2 of Grant County, Washington | 0.486 | | 0.420 |
| * | Public Utility District No. 1 of Grays Harbor County, Washington | 2.769 | 3.075 | 2.386 |
| | Harney Electric Cooperative, Inc., Oregon | 0.105 | 0.719 | 0.221 |
| | City of Heyburn, Idaho | 0.167 | 0.504 | 0.145 |
| | Hood River Electric Cooperative, Oregon | 0.224 | 0.502 | 0.469 |
| | Idaho County Light and Power Cooperative Association, Inc., Idaho | 0.047 | 0.186 | 0.098 |
| | City of Idaho Falls, Idaho, Electric Division | 0.908 | 2.376 | 0.787 |
| | Inland Power & Light Company, Washington | 0.907 | 1.222 | 1.915 |
| * | Public Utility District No. 1 of Kittitas County, Washington | 0.238 | 0.220 | 0.206 |
| * | Public Utility District No. 1 of Klickitat County, Washington | 0.517 | 1.009 | 0.448 |
| | Kootenai Electric Cooperative, Inc., Idaho | 0.212 | 0.391 | 0.443 |
| | Lakeview Light and Power Company, Washington | 0.168 | | |
| | Lane Electric Cooperative, Inc., Oregon | 0.537 | 1.452 | 1.123 |
| * | Public Utility District No. 1 of Lewis County, Washington | 1.276 | 2.274 | 1.103 |
| | Lincoln Electric Cooperative, Inc., Montana | 0.087 | 0.255 | 0.182 |
| | Lost River Electric Cooperative, Inc., Idaho | 0.056 | 0.202 | 0.118 |
| | Lower Valley Power and Light, Inc., Wyoming | 0.266 | 0.820 | 0.557 |
| * | Public Utility District No. 1 of Mason County, Washington | 0.186 | 0.231 | 0.161 |
| * | Public Utility District No. 3 of Mason County, Washington | 1.274 | 1.446 | 1.265 |
| | Town of McCleary, Washington | 0.069 | 0.234 | 0.059 |
| | McMinnville Water and Light, Oregon | 1.141 | 1.227 | 0.547 |
| | Midstate Electric Cooperative, Inc., Oregon | 0.336 | 0.488 | 0.704 |
| | City of Milton, Washington | 0.027 | | |
| | Milton-Freewater Light and Power, Oregon | 0.238 | 0.583 | 0.002 |
| | City of Minidoka, Idaho | 0.001 | 0.005 | 0.001 |
| | Missoula Electric Cooperative, Inc., Montana | 0.168 | 0.294 | 0.352 |
| | City of Monmouth, Oregon | 0.679 | 0.236 | 0.588 |
| | Nespelem Valley Electric Cooperative, Inc., Washington | 0.059 | 0.149 | 0.123 |
| | Northern Lights, Inc., Idaho | 0.234 | 0.455 | 0.489 |
| | Northern Wasco County People's Utility District, Oregon | 0.246 | 0.051 | 0.213 |
| | Ohop Mutual Light Company, Washington | 0.027 | | |
| | Okanogan County Electric Cooperative, Inc., Washington | 0.038 | 0.190 | 0.079 |
| * | Public Utility District No. 1 of Okanogan County, Washington | 0.255 | 1.042 | 0.143 |
| | Orcas Power and Light Company, Washington | 0.257 | 0.725 | 0.733 |
| * | Public Utility District No. 2 of Pacific County, Washington | 1.006 | 1.503 | 0.870 |
| | Parkland Light and Water Company, Washington | 0.096 | | |
| * | Public Utility District No. 1 of Pend Oreille County, Washington | 0.055 | | 0.047 |
| | Peninsula Light Company, Washington | 0.261 | | |
| * | City of Port Angeles, Washington | 0.665 | 2.416 | 0.576 |
| | Raft River Rural Electric Cooperative, Inc., Idaho | 0.224 | 0.853 | 0.468 |
| | Ravalli County Electric Cooperative, Inc., Montana | 0.195 | 0.301 | 0.409 |
| * | City of Richland, Washington, Energy Service Department | 1.828 | 2.780 | 1.592 |
| | Riverside Electric Company, Idaho | 0.007 | 0.020 | 0.015 |
| | City of Rupert, Idaho, Electric Department | 0.123 | 0.348 | 0.106 |

* Energy Northwest members.

| | Participant Utility | Project 1 Share | Columbia Share | Project 3 Share |
|---|---|---|---|---|
| | Salem Electric, Oregon | 0.662 | 0.453 | 1.385 |
| | Salmon River Electric Cooperative, Inc., Idaho | 0.046 | 0.170 | 0.097 |
| * | City of Seattle, Washington, City Light Department | 8.605 | 7.193 | 7.206 |
| * | Public Utility District No. 1 of Skamania County, Washington | 0.321 | 0.547 | 0.278 |
| * | Public Utility District No. 1 of Snohomish County, Washington | 19.584 | 15.363 | 19.334 |
| | South Side Electric Lines, Inc., Idaho | 0.032 | 0.073 | 0.067 |
| | City of Springfield, Oregon, Utility Board | 0.228 | 0.363 | 0.238 |
| | Town of Steilacoom, Washington | 0.038 | | |
| | City of Sumas, Washington | 0.021 | 0.048 | 0.018 |
| | Surprise Valley Electrification Corp., California | 0.049 | 0.323 | 0.102 |
| * | Tacoma Power, Washington | 5.971 | | 5.803 |
| | Tanner Electric Cooperative, Washington | 0.050 | 0.122 | 0.104 |
| | Tillamook People's Utility District, Oregon | 0.963 | 1.729 | 0.833 |
| | Umatilla Electric Cooperative, Oregon | 0.997 | 0.036 | 2.107 |
| | United Electric Cooperative, Inc., Idaho | 0.320 | 0.466 | 0.670 |
| | Vera Water and Power, Washington | 0.323 | 0.701 | 0.401 |
| | Vigilante Electric Cooperative, Inc., Montana | 0.042 | 0.294 | 0.088 |
| * | Public Utility District No. 1 of Wahkiakum County, Washington | 0.229 | 0.328 | 0.198 |
| | Wasco Electric Cooperative, Inc., Oregon | 0.116 | 0.342 | 0.244 |
| | Wells Rural Electric Company, Nevada | 0.102 | | 0.214 |
| | West Oregon Electric Cooperative, Inc., Oregon | 0.121 | 0.182 | 0.252 |
| * | Public Utility District No. 1 of Whatcom County, Washington | 0.387 | | 0.335 |
| | TOTAL PARTICIPANT UTILITIES (111) | 100.000 | 100.000 | 100.000 |

* Energy Northwest members.

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## SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS

The following summary of certain provisions of the Net Billing Agreements, the Project No. 2 Project Agreement (hereinafter referred to as the "Columbia Project Agreement"), and the Assignment Agreements does not purport to be complete. A copy of the foregoing agreements may be obtained from Energy Northwest. The capitalization of any word or words which are not conventionally capitalized indicates that such words are defined in the Net Billing Agreements.

### THE NET BILLING AGREEMENTS

On February 6, 1973, Energy Northwest, Bonneville and each Project 1 Participant entered into a Project 1 Net Billing Agreement. As originally executed, the Project 1 Net Billing Agreements contained a description of Project 1, which included the use of the generating facilities which are a part of the Hanford Generating Project ("HGP"). Subsequently, on May 31, 1974, Energy Northwest, Bonneville and each Project 1 Participant entered into Amendatory Agreement No. 1 to each Project 1 Net Billing Agreement (the "Project 1 Amendatory Agreements"). Under the Project 1 Amendatory Agreements, among other things, the description of Project 1 was changed so that it no longer includes the use of HGP generating facilities. However, the provisions relating to the obligations incurred with respect to HGP after July 1, 1980 remain in effect.

On January 4, 1971, Energy Northwest, Bonneville and each Columbia Participant entered into a Columbia Net Billing Agreement.

On September 25, 1973, Energy Northwest, Bonneville and each Project 3 Participant entered into a Project 3 Net Billing Agreement.

Many of the provisions of the Net Billing Agreements have been summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement. A summary of certain additional provisions of the Net Billing Agreements, as amended, follows. Except where the text indicates otherwise, reference to Project 1 Net Billing Agreements is to such Agreements as amended by the Project 1 Amendatory Agreements. The summary describes the common features of, and highlights the differences among, the Net Billing Agreements for each of Project 1, Columbia and Project 3. Each of the Net Billing Agreements for the same Net Billed Project is identical except as to the Participants' shares.

#### Term

Each Net Billing Agreement became effective upon its execution and delivery and will terminate as provided therein. See "Termination" below.

Although the Net Billing Agreements may be terminated prior to the maturity of the related Net Billed Bonds, the obligation of each of the Participants thereunder to pay its proportionate share of debt service on the related Net Billed Bonds shall continue until such Net Billed Bonds have been retired. Bonneville will continue to be obligated to offset or credit these payments against payments pursuant to the Participant's contracts with Bonneville.

Project 1 and Project 3 have been terminated, and portions of the Project 1 and Project 3 Net Billing Agreements have been terminated. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement.

#### Ownership and Operation

Energy Northwest covenants in the Columbia Net Billing Agreement to use its best efforts to arrange for the financing, design, construction, operation and maintenance of the Columbia Generating Station. Similar covenants of Energy Northwest under the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

#### Sale, Purchase and Assignment

Under the Columbia Net Billing Agreements, Energy Northwest sells, and each Participant purchases, the Participant's share of the Columbia Generating Station capability and each Participant in turn assigns its share of such capability to Bonneville. Such shares in the Columbia Generating Station for the fiscal year 2023 are shown in Appendix F in this Official Statement. Similar provisions in the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

The provisions of the Net Billing Agreements with respect to payments are summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement.

If Bonneville is unable to satisfy its obligation to a Participant by net billing, assignment or cash payment and determines that this condition will continue for a significant period, the affected Participant may direct that all or a portion of the energy associated with its share of the Columbia Generating Station capability be delivered by Energy Northwest for the Participant's account at a specified point of delivery, either for the expected period of such inability or the remainder of the term of the Columbia Net Billing Agreement, whichever is specified by the Participant when it elects to have such energy delivered to it. The amount of energy delivered will be limited to the amount of the Participant's share of the Columbia Generating Station capability for which payment by Bonneville cannot be made.

**Energy Northwest Costs Payable Under Net Billing Agreements**

All costs of Project 1, Columbia and Project 3 are payable under the respective Net Billing Agreements, and the Annual Budgets adopted by Energy Northwest shall make provision for all such costs, including accruals and amortizations, resulting from the ownership, operation (including cost of fuel), and maintenance of Project 1, Columbia and Project 3 and repairs, renewals, replacements, and additions to the Projects, including, but not limited to, the amounts which Energy Northwest is required under the Electric Revenue Bond Resolutions to pay into the various funds provided for in the resolutions for debt service and all other purposes. Each Participant is required to pay the amount specified in the Annual Budget, less amounts payable from sources other than payments under the Net Billing Agreements, multiplied by such Participant's share of Project capability.

**Termination**

If the Columbia Generating Station is ended pursuant to Section 15 of the Columbia Project Agreement, as described below under "THE PROJECT AGREEMENTS," Energy Northwest is required to give notice of termination of the Columbia Net Billing Agreement effective upon the date of termination of such Project Agreement. Energy Northwest will then terminate all activities relating to construction and operation of the Project and shall undertake the salvage and disposition or sale of such Project as provided in the Columbia Project Agreement.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution which terminated Project 1 and a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. In June 1994 the Project 3 Owners Committee voted unanimously to terminate Project 3. In October 1998 Energy Northwest acquired all of the remaining assets of Project 3. Since that time, Energy Northwest has sold a portion of the Project 3 site to the Satsop Redevelopment Project and the balance of the site to Duke Energy Grays Harbor LLC. See "ENERGY NORTHWEST—PROJECT 1," "—PROJECT 3" and "—OTHER ACTIVITIES" and "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Post Termination Agreements."

For a description of payments required to be made following termination of the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement.

**Modification and Assignment of Agreement**

Each Net Billing Agreement provides that it shall not be amended, modified or otherwise changed by agreement of the parties thereto in any manner that will impair or adversely affect the security afforded by each Net Billing Agreement's provision for the payment of the principal, interest, and premium, if any, on the related Net Billed Bonds. The Net Billing Agreements further provide that, except for the reassignments of Participants' shares of Project capability provided for therein, no transfer or assignment of the Net Billing Agreements by any party thereto (except to the United States or an agency thereof) is permitted without the written consent of the other parties and that no assignment or transfer relieves the parties of any obligations thereunder.

**Participants' Review Board**

Each of the Net Billing Agreements for Columbia provides for the establishment of a Participants' Review Board consisting of nine members who are elected by the Participants in Columbia. Except in the event of an emergency requiring immediate action, copies of all bids, evaluations and proposed contracts and awards for amounts in excess of $500,000 shall be submitted to the Participant's Review Board. All Construction and Annual Budgets and fuel management plans, including amendments thereto, and plans for refinancing Columbia are required to be submitted by Energy Northwest to the Participants' Review Board within a reasonable time prior to the time such proposed budgets and plans are adopted by Energy Northwest.

The Net Billing Agreements provide that written recommendations of the Participants' Review Board shall be forwarded to Energy Northwest within a reasonable time and that Energy Northwest will consider such recommendations, giving due regard to Prudent Utility Practice and Energy Northwest's statutory duties. If Energy Northwest modifies or rejects a written recommendation of the Participants' Review Board, the Participants' Review Board may refer the matter to the Project Consultant in the manner described in the Project Agreement for his written decision and his decision shall be binding. Pending any such decision by the Project Consultant, Energy Northwest shall proceed in accordance with the Project Agreement. See "THE PROJECT AGREEMENTS—Term" hereinafter. The Net Billing Agreements provide that the provisions described above shall not affect the procedure for the settlement of any dispute between Bonneville and Energy Northwest under the Net Billing Agreements or the Project Agreement. See "THE PROJECT AGREEMENTS—Bonneville's Approval and Project Consultant" hereinafter in this Appendix G.

Prudent Utility Practice has the same meaning as is given in "THE PROJECT AGREEMENTS—Design, Licensing and Construction of the Project."

The Net Billing Agreements provide that, except as specifically provided in the Project Agreement, Energy Northwest shall not proceed with any item as proposed by it and not concurred in by Bonneville without approval of the Participants' Review Board.

**THE PROJECT AGREEMENTS**

On February 6, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 1 Project Agreement") which, among other things, provided standards for the design, licensing, financing, construction, fueling, operation and maintenance of Project 1, and for the making of any replacements, repairs or capital additions thereto. On May 31, 1974, Energy Northwest and Bonneville entered into Amendatory Agreement No. 1 to the Project 1 Project Agreement for the purpose of changing the description of Project 1 to conform to the changes made in the Project 1 Net Billing Agreements and to revise provisions relating to HGP.

On January 4, 1971, Energy Northwest and Bonneville entered into an agreement (the "Columbia Project Agreement") which, among other things, contains provisions with respect to the licensing, financing, construction, fueling, operation and maintenance of Columbia, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Columbia Net Billing Agreements.

On September 25, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 3 Project Agreement" and, together with the Project 1 Project Agreement and the Columbia Project Agreement, the "Project Agreements") which, among other things, contained provisions with respect to the financing, construction, operation and maintenance of Project 3, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Project 3 Net Billing Agreements.

**Term**

The Project 1 Project Agreement terminated as provided in Section 15 of the Project 1 Project Agreement in May 1994 when the Board of Directors of Energy Northwest adopted a resolution terminating Project 1.

The Columbia Project Agreement became effective upon its execution and delivery and will terminate as follows:

Columbia shall terminate and Energy Northwest shall cause Columbia to be salvaged, discontinued, decommissioned and disposed of or sold, in whole or in part, to the highest bidder or bidders, or disposed of in such other manner as the parties may agree when:

(a) Energy Northwest determines that it is unable to construct, operate, or proceed as owner of Columbia due to licensing, financing, or operating conditions or other causes which are beyond its control,

(b) The parties determine that Columbia is not capable of producing energy consistent with Prudent Utility Practice, or, if the parties disagree, the Project Consultant so determines, or

(c) Bonneville directs the end of Columbia pursuant to the provisions of the Columbia Project Agreement, which provides that if the estimated cost of a replacement or repair or capital addition required by a governmental agency after the date of commercial operation exceeds 20% of the then depreciated value of Columbia, Bonneville may direct that Energy Northwest end Columbia in accordance with Section 15.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. The Project 3 Owners Committee voted unanimously to terminate Project 3 and the Project 3 Project Agreement terminated in June 1994.

**Design, Licensing and Construction of the Project**

In the Columbia Project Agreement, Energy Northwest agrees, among other things, (i) to perform its duties and exercise its rights under such agreement in accordance with Prudent Utility Practice; (ii) to use its best efforts to obtain all licenses, permits and other rights and regulatory approvals necessary for the ownership, construction, and operation of the Project; (iii) to construct the Project in accordance with Prudent Utility Practice; and (iv) to keep Bonneville informed of all significant matters with respect to planning and construction of the Project.

"Prudent Utility Practice," as defined in the Columbia Project Agreement, at a particular time means any of the practices, methods and acts, including those engaged in or approved by a significant portion of the electrical utility industry prior to such time, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. In evaluating whether any matter conforms to Prudent Utility Practice, Bonneville, Energy Northwest and any Project Consultant shall take into account the fact that Energy Northwest is a municipal corporation with statutory duties and responsibilities and the objective to integrate the entire Project capability with the generating resources of the Federal System in order to achieve optimum utilization of the resources of that System taken as a whole and to achieve efficient and economical operation of that System.

**Financing**

Energy Northwest agrees in the Columbia Project Agreement to use its best efforts to issue and sell Columbia Net Billed Bonds (if such Bonds may then be legally issued and sold) to finance the costs of Columbia and of any capital additions, renewals, repairs, replacements or modifications to Columbia.

The Columbia Project Agreement also provides that Energy Northwest may, after submitting its financing proposal to Bonneville, or shall, if requested by Bonneville, authorize the issuance and sale of additional Columbia Net Billed Bonds to refund outstanding Columbia Net Billed Bonds in accordance with the Columbia Net Billed Resolution. A proposal to refund outstanding Columbia Net Billed Bonds is required to be referred to the Project Consultant if, in the judgment of Bonneville or Energy Northwest, no substantial benefits will be achieved by such refunding. See "Bonneville's Approval and Project Consultant" below.

Net Billed Resolutions and resolutions of Energy Northwest supplementing or amending the Net Billed Resolutions are subject to approval by Bonneville, and Bonneville has approved each Net Billed Resolution and each supplemental resolution.

**Budgets**

Separate Annual Budgets for the Net Billed Projects will be prepared annually. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures." The Annual Budget and any amendment thereof are to be submitted to Bonneville for its approval. In the absence of any objection by Bonneville, the Annual Budget will become effective within 30 days after submittal, and within seven days in the case of any amendment thereof. Any item disapproved is required to be referred to the Project Consultant. See "Bonneville's Approval and Project Consultant" below.

**Operation and Maintenance**

Energy Northwest shall operate and maintain Columbia in accordance with Prudent Utility Practice and in accordance with the requirements of government agencies having jurisdiction.

**Bonds for Replacements, Repairs and Capital Additions**

If in any contract year the amounts in an Annual Budget relating to renewals, repairs, replacements and betterments and for capital additions necessary to achieve design capability or required by governmental agencies ("Amounts for Extraordinary Costs"), whether or not such amounts are costs of operation or costs of construction, exceed the amount of reserves, if any, maintained for such purpose pursuant to the Columbia Net Billed Resolutions plus the proceeds of insurance, if any, available by reason of loss or damage to Columbia, by the lesser of (1) $3,000,000, or (2) an amount by which the amount of Bonneville's estimate of the total of the net billing credits available in such contract year to the Participants in Columbia and the amounts of such reserves and insurance proceeds, if any, exceeds the Annual Budget for such contract year exclusive of Amounts for Extraordinary Costs, Energy Northwest is required to, in good faith, use its best efforts to issue and sell Columbia Net Billed Bonds to pay such excess.

**Bonneville's Approval and Project Consultant**

If a proposal submitted by Energy Northwest to Bonneville under any provision of the Columbia Project Agreement is not disapproved by Bonneville within the time specified or, if no time is specified, within seven days after receipt, the proposal is deemed approved. With certain exceptions specified in the Columbia Project Agreement (including Bonneville's right to approve a Net Billed Resolution and any supplemental resolutions), disapproval by Bonneville is required to be based solely on whether the proposal is consistent with Prudent Utility Practice.

If any proposal subject to approval by Bonneville is disapproved by Bonneville and an alternative proposal is suggested by Bonneville, Energy Northwest shall adopt such suggestion or, within seven days after receipt of such disapproval, shall appoint a Project Consultant acceptable to Bonneville to review the proposal. Proposals found by the Project Consultant to be consistent with Prudent Utility Practice shall become immediately effective. Proposals found by the Project Consultant to be inconsistent with Prudent Utility Practice shall be modified to conform to the recommendation of the Project Consultant or as the parties otherwise agree and shall become effective as and when modified. If any proposal referred to the Project Consultant has not been resolved and will affect the continuous operation of Columbia, Energy Northwest shall continue to operate Columbia and may proceed as proposed by Energy Northwest, or as proposed by Bonneville, or as modified by mutual agreement of Energy Northwest and Bonneville. If Energy Northwest proceeds with its proposal, and it is determined by the Project Consultant to be inconsistent with Prudent Utility Practice, Energy Northwest shall bear any net increase in the cost of construction or operation of Columbia resulting from such proposal without charge to Columbia to the extent such proposal is found by the Project Consultant to be inconsistent with Prudent Utility Practice.

**ASSIGNMENT AGREEMENTS**

In 1984 Energy Northwest and Bonneville executed Assignment Agreements for each of Project 1, Columbia and Project 3. The purpose of the Assignment Agreements is to assure that Bonneville receives the entire output of Project 1, Columbia, and Project 3, and to assure that Energy Northwest receives sufficient funds to pay all obligations incurred in connection with such Projects, including debt service.

The Assignment Agreements provide that, subject only to the Participants' rights under the Net Billing Agreements, Energy Northwest assigns to Bonneville any rights which it now has or may hereafter obtain in project capability by a reversion of any Participant's share in Project capability to Energy Northwest or by any other means. Bonneville accepted this assignment, and in the event that any Participant is determined not to be obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agrees to pay directly to Energy Northwest the amounts that would have been payable under the Net Billing Agreements for such Project capability.

The Assignment Agreements are designed to assure that Bonneville will obtain any interest Energy Northwest has or may hereafter obtain in Project capability, subject only to the Participants' rights and obligations under the Net Billing Agreements, and that the same economic and practical consequences will result for Bonneville and Energy Northwest as if Bonneville had acquired such interest in Project capability pursuant to the assignment of Project capability contained in the Net Billing Agreements.

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## SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS

The following summary is an outline of certain provisions contained in the Electric Revenue Bond Resolutions and the Supplemental Electric Revenue Bond Resolutions and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Electric Revenue Bond Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the Trustee. Capitalized terms not otherwise defined in this Appendix H shall have the meanings ascribed to them in this Official Statement.

**Definitions**

"*Authorized Purpose*" shall mean any one or more of the purposes described in Section 201 of the Electric Revenue Bond Resolutions.

"*Bank Bond*" shall mean any Electric Revenue Bond owned by the Related Credit Issuer or its permitted assigns in connection with the provision of moneys under the Related Credit Facility.

"*Code*" shall mean the Internal Revenue Code of 1986, as amended and supplemented from time to time, and the applicable temporary, proposed, or final regulations promulgated by the United States Treasury Department thereunder or under the Internal Revenue Code of 1954, as amended.

"*Credit Facility*" shall mean a letter of credit, line of credit, insurance policy, surety bond, standby bond purchase agreement or standby payment agreement or similar obligation or instrument or any combination of the foregoing issued by a bank, insurance company or similar financial institution or by the parent corporation of any of the foregoing or by the State or the Federal Government or any agency, authority, instrumentality or subdivision thereof, including, without limitation, the Administrator.

"*Debt Service Deposit Date*" shall mean any date on which a deposit is required to be made into the related Debt Service Fund by each Electric Revenue Bond Resolution or any Supplemental Electric Revenue Bond Resolution.

"*Defeasance Obligations*" shall mean (a) any of the obligations described in clause (i) of the definition of Investment Securities, (b) Refunded Municipal Obligations, and (c) with respect to any Series of Electric Revenue Bonds, such other obligations as are described in the Supplemental Electric Revenue Bond Resolutions authorizing such Series. The Supplemental Electric Revenue Bond Resolutions authorizing the Series 2023-A Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2023-A Bonds, any "Government Obligations" as that term is defined in Chap. 39.53 RCW and as it may be hereafter amended.

"*Electric Revenue Bond Resolution*" shall mean Resolution No. 835, adopted on November 23, 1993, as amended and supplemented, Resolution No. 1042, adopted on October 23, 1997, as amended and supplemented, and Resolution No. 838, adopted on November 23, 1993, as amended and supplemented.

"*Engineer*" shall mean any nationally recognized independent engineer or engineering firm appointed by Energy Northwest.

"*Government Obligations*" means (a) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (b) bonds, debentures, notes, participation certificates, or other obligations issued by the banks for cooperatives, the federal intermediate credit bank, the federal home loan bank system, the export-import bank of the United States, federal land banks, or the federal national mortgage association; (c) public housing bonds and project notes fully secured by contracts with the United States; and (d) obligations of financial institutions insured by the federal deposit insurance corporation or the federal savings and loan insurance corporation, to the extent insured or to the extent guaranteed as permitted under any provision of state law, as such definition may be amended.

"*Investment Securities*" shall mean any of the following, if and to the extent that the same are legal for the investment of funds of Energy Northwest:

(i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America;

(ii) obligations of any agency, subdivision, department, division or instrumentality of the United States of America, including, without limitation, the Federal Home Loan Mortgage Corporation, the Federal Agricultural Mortgage Corporation, the Student Loan Marketing Association and the International Bank for Reconstruction and Development; or obligations fully guaranteed as to interest and principal by any agency, subdivision, department, division or instrumentality of the United States of America;

(iii) direct obligations of, or obligations guaranteed as to principal and interest by, any state or direct obligations of any agency or public authority thereof, insured or uninsured, provided such obligations are rated, at the time of purchase, in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(iv) bank time deposits evidenced by certificates of deposit and bankers' acceptances issued by any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), provided that such time deposits and bankers' acceptances (a) do not exceed at any one time in the aggregate five percent (5%) of the total of the capital and surplus of such bank or trust company, or (b) are secured by obligations described in items (i) or (ii) of this definition of Investment Securities, which such obligations at all times have a market value at least equal to such time deposits so secured;

(v) repurchase agreements with (1) any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), or (2) any securities broker which is a member of the Securities Investor Protection Corporation, which such agreements are secured by securities which are obligations described in items (i) or (ii) of this definition of Investment Securities, provided that each such repurchase agreement (a) is in commercially reasonable form and is for a commercially reasonable period, and (b) results in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the repurchaser) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest; provided that such securities acquired pursuant to such repurchase agreements shall be valued at the lower of the then current market value of such securities or the repurchase price thereof set forth in the applicable repurchase agreement;

(vi) certificates or other obligations that evidence ownership of the right to payments of principal of or interest on obligations of the United States of America or any state of the United States of America or any political subdivision thereof or any agency or instrumentality of the United States of America or any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a Trustee under the Electric Revenue Bond Resolutions, and provided further that, in the case of certificates or other obligations that evidence ownership of the right to payments of principal or interest on obligations of a state or political subdivision, the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which shall be rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(vii) investment agreements rated in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds or the long-term unsecured debt obligations of the issuer of which are rated in one of the two highest rating categories by the respective agency rating such investment agreements or investment agreements which result in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the counterparty to the investment agreement) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest;

(viii) bankers' acceptances drawn on and accepted or guaranteed by a commercial bank rated in either of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(ix) commercial paper rated, at the time of purchase, in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(x) shares of any publicly offered mutual fund of the type commonly known as a "money market fund" that, at the time of investment, has at least 85% of its assets directly invested in securities of the type described in items (i), (ii) and (iii) of this definition of Investment Securities; and

(xi) such other investments with respect to any Series of Electric Revenue Bonds as shall be specified in the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Outstanding*" or "*outstanding*" shall mean, as if any date, (a) when used with reference to Electric Revenue Bonds, all Electric Revenue Bonds theretofore or thereupon issued or authorized pursuant to the Electric Revenue Bond Resolution, except: (i) any Electric Revenue Bonds paid in full, surrendered for cancellation or cancelled at or prior to such date (including any Bond held in escrow pending settlement of any tender offer by Energy Northwest or the Trustee on its behalf, but excluding any Option Bond so held pending settlement of a purchase on a tender date); and (ii) Electric Revenue Bonds in lieu of or in substitution for which other Electric Revenue Bonds shall have been authenticated or delivered pursuant to the Electric Revenue Bond Resolution; and (iii) Electric Revenue Bonds deemed to be no longer outstanding under the Electric Revenue Bond Resolution as provided therein or under any Supplemental Resolution authorizing the issuance of a Series of Electric Revenue Bonds, and (b) when used with reference to Subordinate Lien Obligations shall have the meaning assigned to such term by the instrument or instruments under which such Subordinate Lien Obligations are issued.

"*Parity Debt*" shall mean bonds, notes or other obligations issued under a resolution or resolutions authorized pursuant to the Electric Revenue Bond Resolutions, the Electric Revenue Bonds and any Parity Reimbursement Obligation.

"*Parity Reimbursement Obligation*" shall mean a reimbursement obligation the payment of which, pursuant to the provisions of a Supplemental Electric Revenue Bond Resolution, is secured as to payment by the pledge created by the Electric Revenue Bond Resolutions.

"*Payment Agreement*" shall mean a written agreement which provides for an exchange of payments based on interest rates, or for ceilings or floors on such payments, or an option on such payments, or any combination, entered into on either a current or forward basis.

"*Payment Date*" shall mean each date on which interest shall be due and payable and each date on which both interest shall be due and payable and a scheduled Principal Installment (whether by payment of principal scheduled to mature or a sinking fund installment to be paid) shall be required to be made on any of the outstanding Electric Revenue Bonds according to their respective terms.

"*Principal Installment*" shall mean, as of any date of calculation and with respect to any Series or Subseries, as the case may be, (a) the principal amount of Electric Revenue Bonds (including any amount designated in, or determined pursuant to, the applicable Supplemental Electric Revenue Bond Resolution, as the "principal amount" with respect to any bonds) of such Series or subseries scheduled to mature on a certain future date for which no sinking fund installments have been established, or (b) the unsatisfied balance of sinking fund installments scheduled to be paid on a certain future date for Electric Revenue Bonds of such Series or subseries, or (c) if such future dates coincide as to different Electric Revenue Bonds of such Series or subseries, the sum of such principal amount and such unsatisfied balance scheduled to mature or to be paid on such future date; in each case in the amounts and on the dates as provided in the applicable Supplemental Electric Revenue Bond Resolution authorizing such Series or subseries regardless of any retirement of Electric Revenue Bonds except pursuant to Section 505 of the Electric Revenue Bond Resolutions or (d) that portion of a Parity Reimbursement Obligation which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid or that portion of a Parity Reimbursement Obligation payable on a certain future date which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid.

"*Rating Agency*" shall mean Fitch, Inc. ("Fitch"), Moody's Investors Service, Inc. ("Moody's") or S&P Global Ratings ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

"*Refunded Municipal Obligations*" shall mean obligations of any state, the District of Columbia or possession of the United States of America or any political subdivision thereof, which obligations are rated in the highest rating category by at least two nationally recognized rating agencies and provision for the payment of the principal of and interest on which shall have been made by deposit with a Trustee or escrow agent of direct obligations of, or obligations guaranteed by, the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or any state, the District of Columbia or possession thereof in the capacity as custodian, the maturing principal of and interest on which when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession or political subdivision.

"*Reserve Account Requirement*" shall mean, with respect to a Series of Electric Revenue Bonds, the amount, if any, prescribed by the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Reserve Guaranty*" shall mean an insurance policy or surety bond provided by an insurer whose claims-paying ability is rated in either of the two highest rating categories by at least two nationally recognized rating agencies, or a letter of credit or other similar Credit Facility the long-term unsecured debt of the issuer of which is rated in either of the two highest rating categories by at least two nationally recognized rating agencies.

"*Revenues*" shall mean all income, revenues, receipts and profits derived by Energy Northwest through the ownership and operation by Energy Northwest of the related Project and all other moneys required to be deposited in the Revenue Fund.

"*Subordinate Lien Obligation*" shall mean any bond, note, certificate, warrant or other evidence of indebtedness of Energy Northwest authorized by the Electric Revenue Bond Resolution.

**Effect of Amendments Adopted March 9, 2001 (Project 1, Columbia and Project 3)**

The Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, amend the Project 1, Columbia and Project 3 Electric Revenue Bond Resolutions, respectively, to add a covenant to the effect that, from and after the issuance of the Series 2001-A Bonds, Energy Northwest shall not otherwise create any other special fund or funds for the payment of bonds, warrants or other obligations which will rank on a parity with the pledge and lien on the Revenues created by any prior lien resolution.

Each Supplemental Resolution also amends the related Electric Revenue Bond Resolution to add a definition of the term "Energy Northwest" and to change the definition of the term "System," as follows:

"*Energy Northwest*" shall mean the joint operating agency organized and existing under the provisions of the Act and formerly known as the Washington Public Power Supply System.

"*System*" shall mean Energy Northwest.

The Project 1 Supplemental Resolution further amends the Project 1 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 1 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 1 Electric Revenue Bond Supplemental Resolution, shall be known as "Energy Northwest Project 1 Electric Revenue Bonds."

The Columbia Supplemental Resolution further amends the Columbia Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution, from and after the date of adoption of the Columbia Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Columbia Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Columbia Generating Station Electric Revenue Bonds."

The Project 3 Supplemental Resolution further amends the Project 3 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 3 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 3 Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Project 3 Electric Revenue Bonds."

**Electric Revenue Bond Resolutions to Constitute Contract (Section 103)**

Each Electric Revenue Bond Resolution constitutes a contract between Energy Northwest and the owners from time to time of the Electric Revenue Bonds, and the issuer of a Credit Facility, if any, relating to such subseries of Electric Revenue Bonds; and the pledge made in each related Electric Revenue Bond Resolution and the covenants and agreements therein set forth to be performed on behalf of Energy Northwest shall be for the equal benefit, protection and security of the owners of any and all of the Electric Revenue Bonds and the issuer of any related Credit Facility where the obligation of Energy Northwest to reimburse such issuer is a Parity Reimbursement Obligation, each of which, regardless of time or times of maturity or due dates, shall be of equal rank without preference, priority or distinction of the Electric Revenue Bonds over any other thereof except as expressly provided in or permitted by the Electric Revenue Bond Resolutions.

**Authorization of Bonds (Section 201)**

The Project 1 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 1 Electric Revenue Bonds," the Columbia Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Columbia Electric Revenue Bonds," and the Project 3 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 3 Electric Revenue Bonds."

The Electric Revenue Bonds may be issued under each Electric Revenue Bond Resolution from time to time in series, which may consist of two or more subseries, pursuant and subject to the terms, conditions and limitations of the Electric Revenue Bond Resolutions and any Supplemental Electric Revenue Bond Resolutions providing for the issuance of Electric Revenue Bonds, in such amounts as may be determined by Energy Northwest, for one or more of the following purposes: (i) refunding any Outstanding Electric Revenue Bond or any Outstanding Subordinate Lien Obligation; (ii) the payment, or reimbursement of Energy Northwest for the payment, of the costs of the acquisition, construction or installation of additional facilities or modifications to the related Project in compliance with the order or decision of any State or Federal agency or authority having competent jurisdiction; (iii) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of making renewals, repairs, replacements, improvements or betterments to the related Project, including costs associated with the upgrading of the output capacity of the related Project, including expenses incurred in connection with the upgrading of any operating license in connection therewith; (iv) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of capital additions, improvements or betterments to the related Project necessary to achieve design capability; (v) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of (1) decommissioning the related Project or (2) restoring the site of the related Project, in compliance with applicable Federal or State law or any order or decision of any State or Federal agency or authority having competent jurisdiction; (vi) payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of purchasing fuel for the related Project; (vii) providing funds for deposit into the Reserve Accounts or any other reserves established by any Supplemental Electric Revenue Bond Resolution for the payment of the principal of or interest on the Series of Electric Revenue Bonds authorized thereby and paying the costs incident to the issuance of such Series of Electric Revenue Bonds; and (viii) the payment, or the reimbursement of Energy Northwest for the payment, of the costs of any other purpose permitted by law.

**Pledge Effected by the Electric Revenue Bond Resolutions (Section 202)**

Energy Northwest pledges for the payment of the principal or redemption price of and interest on the Electric Revenue Bonds in accordance with their terms and the provisions of the Electric Revenue Bond Resolutions (i) the proceeds of the sale of the Electric Revenue Bonds pending application thereof in accordance with the provisions of the applicable Electric Revenue Bond Resolution or of any applicable Supplemental Electric Revenue Bond Resolution, (ii) subject to the provisions of each Electric Revenue Bond Resolution, all revenues, and (iii) the Debt Service Fund established by each Electric Revenue Bond Resolution, including the investments, if any, therein; provided, however, that, subject to each Electric Revenue Bond Resolution, amounts on deposit to the credit of any Reserve Account in the Debt Service Funds are pledged only to the Series of Electric Revenue Bonds for which such Reserve Account was established pursuant to the Supplemental Electric Revenue Bond Resolutions authorizing such Series and may be applied only to pay the principal or redemption price, if any, of and interest on the Electric Revenue Bonds of such Series.

Except as may be otherwise provided in the Electric Revenue Bond Resolutions or in the Supplemental Electric Revenue Bond Resolutions authorizing a Series of Electric Revenue Bonds, the Electric Revenue Bonds of each such Series shall be equally and ratably payable and secured under the related Electric Revenue Bond Resolution without priority by reason of the date of adoption of the Supplemental Electric Revenue Bond Resolutions providing for their issuance or by reason of their Series or subseries, number or date, date of issue, execution, authentication or sale thereof, or otherwise.

The revenues and other moneys pledged and received by Energy Northwest shall immediately be subject to the lien of the pledge made by Energy Northwest under each Supplemental Electric Revenue Bond Resolution without any physical delivery or further act, and the lien of the pledge shall be valid and binding as against any parties having claims of any kind in tort, contract or otherwise against Energy Northwest, irrespective of whether such parties have notice thereof.

**Refunding Bonds (Section 204)**

All Electric Revenue Bonds issued to refund Outstanding Electric Revenue Bonds shall be authenticated and delivered by the Trustee only upon receipt by it, in addition to other documents required by the Electric Revenue Bond Resolutions (and in addition to further documents required by the provisions of any Supplemental Electric Revenue Bond Resolutions), of:

(i) irrevocable instructions to the Trustee, satisfactory to it, to give due notice of redemption of all the Electric Revenue Bonds to be redeemed on a redemption date or dates specified in such instructions;

(ii) if the Electric Revenue Bonds to be refunded are not to be redeemed within the next succeeding 90 days, irrevocable instructions to the Trustee, satisfactory to it, to give due notice of any refunding of such Electric Revenue Bonds on a specified date prior to their maturity, as provided in Article VI of each Electric Revenue Bond Resolution or in the Supplemental Electric Revenue Bond Resolution which authorized such Electric Revenue Bonds to be refunded, and Section 1101 of each Electric Revenue Bond Resolution;

(iii) either (A) moneys (which may include all or a portion of the proceeds of the refunding Electric Revenue Bonds to be issued) in an amount sufficient to effect payment of the principal or the redemption price of the Electric Revenue Bonds to be refunded, together with accrued interest on such Electric Revenue Bonds to the maturity or redemption date thereof, as the case may be, or (B) Defeasance Obligations in such principal amounts, of such maturities, bearing such interest and otherwise having such terms and qualifications and any moneys, as shall be necessary to comply with the provisions of Section 1101 of each Electric Revenue Bond Resolution, which Defeasance Obligations and moneys shall be held in trust and used only as provided in Section 1101 of each Electric Revenue Bond Resolution; and

(iv) such further documents and moneys as are required by the provisions of each Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolutions.

**Subordinate Obligations (Section 205)**

Nothing contained in the Electric Revenue Bond Resolutions prohibits or prevents Energy Northwest from authorizing and issuing bonds, notes, certificates, warrants or other evidences of any indebtedness for any purpose relating to the Net Billed Projects payable as to principal and interest from the revenues subject and subordinate to the deposits and credits required to be made to the funds established under the Electric Revenue Bond Resolutions or from securing such bonds, notes, certificates, warrants or other evidences of indebtedness and the payment thereof by a lien and pledge on the revenues junior and inferior to the lien and the pledge on the revenues created by the Electric Revenue Bond Resolutions.

**Credit Facilities (Section 208)**

Electric Revenue Bond Supplemental Resolutions providing for the issuance of a Series of Electric Revenue Bonds may provide that Energy Northwest obtain or cause to be obtained Credit Facilities providing for payment of all or a portion of the purchase price or Principal Installment or Redemption Price of, or interest due or to become due on specified Electric Revenue Bonds of such Series or any Subseries thereof, or providing for the purchase of such Electric Revenue Bonds or a portion thereof by the issuer of the Credit Facilities, or providing, in whole or in part, for the funding of the Reserve Accounts pursuant to Section 505 of each Electric Revenue Bond Resolution, provided such Credit Facility is a Reserve Guaranty. In connection therewith, Energy Northwest may enter into agreements with the issuers of the Credit Facility to provide for the terms and conditions thereof, including the security, if any, to be provided to such issuers.

Energy Northwest may secure the applicable Credit Facility by an agreement providing for the purchase of the Electric Revenue Bonds secured thereby with such adjustments to the rate of interest, method of determining interest, maturity, or redemption provisions as specified in the Supplemental Electric Revenue Bond Resolutions. Interest with respect to any Series of Electric Revenue Bonds so secured shall be calculated for purposes of the Reserve Account Requirement for such Series by using the actual rate of interest or, if applicable, the Certified Interest Rate on the Electric Revenue Bonds prior to adjustment under such agreement. Energy Northwest may also agree to reimburse directly the issuers of the Credit Facilities for any amounts paid thereunder together with interest thereon. Energy Northwest may provide that any such obligations to reimburse shall be Parity Reimbursement Obligations. In addition, Energy Northwest may, in connection with any such Credit Facility, agree to pay the fees and expenses of, and other amounts payable to, the issuers of such Credit Facilities, the payment of which may be secured by pledges of revenues, funds and other moneys pledged pursuant to the Electric Revenue Bond Resolutions on a parity with the pledges created by the Electric Revenue Bond Resolutions.

**Establishment of Funds (Section 502)**

The following special trust funds are established by each Electric Revenue Bond Resolution:

(a) General Revenue Fund, to be held and maintained by Energy Northwest; and

(b) Debt Service Fund, to be held and maintained by the Trustee. The Debt Service Fund shall include a separate Debt Service Account for each Series of Electric Revenue Bonds and a separate subaccount for each subseries of Electric Revenue Bonds issued under each Electric Revenue Bond Resolution and each such Debt Service Account and subaccount shall be designated using the designation of the Series or subseries, if any, to which such Debt Service Account or subaccount relates.

The existence of such funds shall be continued for so long as any Electric Revenue Bonds remain outstanding. Energy Northwest may establish pursuant to Supplemental Electric Revenue Bond Resolutions authorizing the issuance of Electric Revenue Bonds, additional funds, accounts and subaccounts for the purposes designated in such Supplemental Electric Revenue Bond Resolutions.

**Disposition of Revenues (Section 503)**

Energy Northwest covenants and agrees that it will pay into each General Revenue Fund as promptly as practical after receipt thereof all revenues and all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

**General Revenue and Debt Service Funds (Sections 504 and 505)**

*General Revenue Fund*. The amounts on deposit in each General Revenue Fund shall be trust funds in the hands of Energy Northwest and, subject to certain provisions described herein, shall be used and applied as provided in the applicable Electric Revenue Bond Resolution solely for the purpose of paying principal and interest on Parity Debt, the cost of operating and maintaining the related Project and paying all other costs, charges and expenses in connection with the costs of making repairs, renewals, replacements, additions, betterments and improvements to and extensions of the related Project and for purposes of paying all other charges and obligations against said revenues, income, receipts, profits and other moneys of whatever nature now or hereafter imposed thereon by law or contract, to the payment of which for such purposes said revenues and other moneys are pledged, including amounts required to be paid to the issuers of any Credit Facility pursuant to the provisions of any related Supplemental Electric Revenue Bond Resolution.

Energy Northwest shall pay, from the moneys on deposit in each General Revenue Fund, to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that the moneys on deposit in the General Revenue Fund shall be insufficient to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt and to each person thereof entitled thereto, as applicable, its pro rata share of the amounts on deposit in the General Revenue Fund. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the last Business Day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each relevant debt service subaccount in the related Debt Service Account, the amount, which, when added to the amount, if any, then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each sinking fund installment required to be paid, and the amount of interest due and payable, or, if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund, and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, required to be so paid pursuant to the provisions of the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the applicable Electric Revenue Bond Resolution to be so deposited.

*Debt Service Fund*. The Trustee shall, for each Series or Subseries of Electric Revenue Bonds Outstanding, pay from the moneys on deposit in each relevant Debt Service Account or subaccount of each Debt Service Fund (i) the amounts required for the payment of the principal, if any, due on each Payment Date, (ii) the amount required for the payment of interest due on each Payment Date, (iii) on any redemption date the amounts required to pay the redemption price of the Electric Revenue Bonds to be redeemed on such date, unless the payment of such redemption price shall be otherwise provided, (iv) on any redemption date or date of purchase, the amounts required for the payment of accrued interest on Electric Revenue Bonds to be redeemed or purchased on such date unless the payment of such accrued interest shall be otherwise provided, and (v) at the times and in the manner provided in the related Supplemental Electric Revenue Bond Resolution and the agreements between Energy Northwest and any issuer of a Credit Facility or counterparty to any Payment Agreement, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts provided to be so paid.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, Energy Northwest may, prior to the forty-fifth day preceding the due date of any sinking fund installment purchase Electric Revenue Bonds of the Series or Subseries, as the case may be, and maturity for which such sinking fund installment was established, at prices (including any brokerage and other charges) not exceeding the redemption price payable for such Electric Revenue Bonds when such Electric Revenue Bonds are redeemable by application of such sinking fund installment plus unpaid interest accrued to the date of purchase, such purchases to be made by the Trustee as directed in writing by an authorized officer of Energy Northwest.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, upon the purchase or redemption (other than by application of sinking fund installments) of any Electric Revenue Bond, an amount equal to the principal amount of the Electric Revenue Bond so purchased or redeemed shall be credited toward the sinking fund installments thereafter to become due as directed in writing by an authorized officer of Energy Northwest.

Energy Northwest may, at its option, in lieu of depositing all or any part of the sinking fund installments into each relevant Debt Service Account or subaccount thereof of each Debt Service Fund, furnish the Trustee with a Certificate of an authorized officer stating that Energy Northwest has purchased for cancellation term bonds of a Series or Subseries of Electric Revenue Bonds in the principal amount, and bearing the numbers, specified therein, and that said term bonds have not been previously included in any such Certificate; and thereupon the sinking fund installments with respect to the term bonds of such Series or subseries, as the case may be, may be reduced by the principal amount of such term bonds canceled, as provided by such Certificate.

Unless otherwise provided for a Series of Electric Revenue Bonds or subseries thereof, as the case may be, in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, as soon as practicable after the forty-fifth day preceding the due date of any such sinking fund installment, the Trustee shall proceed to call for redemption, pursuant to Article IV of each Electric Revenue Bond Resolution or the applicable Supplemental Electric Revenue Bond Resolutions, as the case may be, on such due date, Electric Revenue Bonds of the Series or subseries, as the case may be, and maturity for which such sinking fund installment was established in such amount as shall be necessary to complete the retirement of the principal amount specified for such sinking fund installment of the Electric Revenue Bonds of such Series or subseries, as the case may be, and maturity. The Trustee shall so call such Electric Revenue Bonds for redemption whether or not it then has moneys in each Debt Service Account or subaccount thereof of each Debt Service Fund established for such Series or subseries, as the case may be, sufficient to pay the applicable redemption price thereof on the redemption date. The Trustee shall apply to the redemption of the Electric Revenue Bonds on each such redemption date, the amount required for the redemption of such Electric Revenue Bonds.

**Bond Proceeds Funds (Section 507)**

The Supplemental Electric Revenue Bond Resolution providing for the issuance of any Series of Electric Revenue Bonds (exclusive of Refunding Bonds) will create and establish one or more special trust funds into which the proceeds of such Series of Electric Revenue Bonds will be deposited and from which such proceeds will be disbursed to pay the Costs of the Authorized Purpose or Purposes for which such Series of Electric Revenue Bonds were issued (unless such Supplemental Electric Revenue Bond Resolution will provide for the deposit of such proceeds in one or more of such funds theretofore created and established). Each such fund (a "Bond Proceeds Fund") will be held in trust by Energy Northwest, for the benefit of the owners of the Electric Revenue Bonds pending application thereof in accordance with the terms of the related Supplemental Electric Revenue Bond Resolution. Payments from Bond Proceeds Fund will be as specified in the Supplemental Electric Revenue Bond Resolution authorizing the issuance of a related Series of Electric Revenue Bonds.

Amounts on deposit in any Bond Proceeds Fund, pending their application as provided in the Supplemental Electric Revenue Bond Resolution creating such Bond Proceeds Fund, will be subject to a prior and paramount lien and charge in favor of the owners of the Electric Revenue Bonds, and the owners of the Electric Revenue Bonds will have a valid claim on such moneys for the further security of the Electric Revenue Bonds until paid out or transferred as herein provided.

**Investment of Funds (Section 508)**

Moneys held in each Debt Service Fund shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee upon request of Energy Northwest (promptly confirmed in writing) solely in Investment Securities which shall mature or be subject to redemption at the option of the owner thereof on or prior to the respective dates when the moneys therein will be required for the purposes intended. However, moneys in each Reserve Account in each Debt Service Fund not required for immediate disbursement for the purpose for which said Account is created shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee at the direction of Energy Northwest (promptly confirmed in writing) solely in, and obligations credited to each Reserve Account shall be, Investment Securities which, unless otherwise provided in the related Supplemental Electric Revenue Bond Resolution, shall mature or be subject to redemption at the option of the owner thereof on or prior to the last maturity date of the related Series of Electric Revenue Bonds. The Trustee shall not be liable for any depreciation in value of any such investments. For the purpose of Section 508 of the Electric Revenue Bond Resolutions, the term "Investment Securities" shall be limited to obligations described in clauses (i) and (v) of the definition of Investment Securities.

Nothing in the Electric Revenue Bond Resolutions shall prevent any Investment Securities acquired as investments of funds held thereunder from being issued or held in book-entry form.

**Valuation or Sale of Investments (Section 509)**

Investment Securities in any fund or account created under the provisions of each Electric Revenue Bond Resolution shall be deemed at all times to be part of such fund or account and any profit realized from the liquidation of such investment shall be credited to such fund or account and any loss resulting from liquidation of such investment shall be charged to such fund or account. Any such net profits or excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest, or paid to, or retained in, each General Revenue Fund.

In computing the amount in any fund or account, Investment Securities therein shall be valued at cost or, if purchased at a premium or discount, at their amortized value. Any such computation shall include accrued interest on the Investment Securities paid as part of the purchase price thereof and not repaid. Such computation shall be made annually on June 30th for all funds and accounts established pursuant to the Electric Revenue Bond Resolutions and at such other times as Energy Northwest shall determine or as may be required by the Electric Revenue Bond Resolutions.

Except as otherwise provided in the Electric Revenue Bond Resolutions, the Trustee, as directed by an authorized officer of Energy Northwest (promptly confirmed in writing), shall use its best efforts to sell at the best price obtainable, or present for redemption, any Investment Securities held by the Trustee in any fund or account whenever it shall be necessary, and upon oral request (promptly confirmed in writing) from an authorized officer of Energy Northwest in order to provide moneys to meet any payment or transfer from such fund or account. The Trustee shall not be liable or responsible for any loss resulting from any such investment, sale, liquidation or presentation for investment made in the manner provided above.

Subject to the foregoing limitations, any moneys held by Energy Northwest or the Trustee under a particular Electric Revenue Bond Resolution may be pooled in order to make any purchase of Investment Securities or deposit of moneys held under such Electric Revenue Bond Resolution, which purchases or deposits are otherwise permitted thereunder; provided, however, that Energy Northwest and the Trustee shall at all times keep accurate and complete records of the Investment Securities so purchased and deposits so made in sufficient detail as will permit the application of such Investment Securities and deposits, and the proceeds thereof, solely for the purposes, at the times and in the manner provided in each Electric Revenue Bond Resolution.

**Qualifications and Appointment of Trustee; Resignation or Removal Thereof; Successor Thereto (Section 601)**

In the Supplemental Electric Revenue Bond Resolution providing for the issuance of the initial Series of Electric Revenue Bonds, Energy Northwest shall appoint a Trustee (the "Trustee") to hold and administer the Funds and Accounts created and established in each Electric Revenue Bond Resolution. The Trustee will be a commercial bank with trust powers or trust company with capital stock, surplus and undivided profits aggregating in excess of $50,000,000. The Trustee may be removed at the request of or upon the affirmative vote of (i) the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, or (ii) a majority of the members of the Executive Board of Energy Northwest, provided, however, that the Trustee may not be removed pursuant to the preceding clause (ii) upon the occurrence of an Event of Default or while such an Event of Default shall be continuing: provided further, that any removal will not take effect until the appointment of a successor and the acceptance by such successor in accordance with each Electric Revenue Bond Resolution.

In the event of the removal pursuant to clause (i) of the preceding sentence, resignation, disability or refusal to act of the Trustee, a successor may be appointed by the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, excluding any Electric Revenue Bonds held by or for the account of Energy Northwest, and such successor shall have all the powers and obligations of the Trustee under each Electric Revenue Bond Resolution theretofore vested in its predecessor; provided, that unless a successor Trustee has been appointed by the owners of Electric Revenue Bonds as aforesaid, Energy Northwest by a duly executed written instrument signed by a majority of the members of the Executive Board will concurrently appoint a Trustee to fill such vacancy until a successor Trustee will be appointed by the owners of Electric Revenue Bonds as authorized in this paragraph. Any successor Trustee appointed by Energy Northwest pursuant to this paragraph will, immediately and without further act, be superseded by a Trustee so appointed by the owners of Electric Revenue Bonds.

In the event of the removal of the Trustee pursuant to clause (ii) above, Energy Northwest will appoint a successor Trustee.

Any Trustee may resign at any time by giving not less than 180 days' notice to Energy Northwest in writing and to the Bondholders by publishing a notice of resignation in an Authorized Newspaper once within 10 days after the giving of such notice to the Energy Northwest; provided, however, that such resignation shall not take effect until the appointment of a successor and the acceptance of such successor in accordance with this Resolution.

The resigning Trustee, if within 50 days after the publication of notice of its resignation no successor Trustee has been appointed and accepted such appointment, may petition any court of competent jurisdiction for the appointment of a successor Trustee, or any owner of a Bond who has been an owner of a Bond for at least six months may, on behalf of such owner and others similarly situated, petition any such court for the appointment of a successor Trustee. Such court may thereupon, after such notice, if any, appoint a successor Trustee having the qualifications required hereby.

In case at any time any of the following shall occur: (i) any Trustee ceases to be eligible in accordance with the provisions of each Electric Revenue Bond Resolution and fails to resign after written request therefor has been given to such Trustee by Energy Northwest or by any owner of a Bond who has been a bona fide owner of a Bond for at least six months, or (ii) any Trustee becomes incapable of acting, or is adjudged a bankrupt or insolvent, or a receiver of such Trustee or of its property is appointed, or any public officer takes charge or control of such Trustee or of its property or affairs for the purpose of rehabilitation, conservation or liquidation, or (iii) any Trustee neglects or fails in the performance of its duties under each Electric Revenue Bond Resolution, then, in any such case, Energy Northwest may remove such Trustee by an instrument in writing signed by an Authorized Officer or any such owner of a Bond may, on behalf of himself and all others similarly situated, petition any court of competent jurisdiction for the removal of such Trustee. Such court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, remove such Trustee.

Any successor Trustee shall meet the qualifications of each Electric Revenue Bond Resolution. Such successor Trustee will execute, acknowledge and deliver to its predecessor, and also to Energy Northwest, an instrument in writing accepting such appointment under each Electric Revenue Bond Resolution, and thereupon such successor Trustee, without any further acts, deed or conveyance, shall become fully vested with all the rights, powers, trusts, duties and obligations of its predecessor in trust under each Electric Revenue Bond Resolution, with like effect as if originally named as Trustee; but such predecessor will, nevertheless, on the written request of Energy Northwest or such successor Trustee, execute and deliver an instrument transferring to such successor Trustee all rights, powers, trusts, duties and obligations of such predecessor in trust under each Electric Revenue Bond Resolution and will deliver all moneys held by it to such successor Trustee, together with an accounting of funds held by it under each Electric Revenue Bond Resolution. The successor Trustee will have no responsibility for the acts of the predecessor Trustee.

Upon acceptance of appointment by the successor Trustee, as provided in this Section, Energy Northwest will publish notice of the succession of such Trustee to the trusts hereunder at least once in an Authorized Newspaper. If Energy Northwest fails to publish such notice, within 10 days after acceptance of appointment by the successor Trustee, the successor Trustee will cause such notice to be published at the expense of Energy Northwest.

Any corporation into which a Trustee may be merged or with which it may be consolidated, or any corporation resulting from any merger or consolidation to which a Trustee is a party, or any corporation to which a Trustee may sell or transfer all or substantially all of its corporate trust business, will be the successor Trustee under each Electric Revenue Bond Resolution without the execution or filing of any paper or any further act on the part of the parties to each Electric Revenue Bond Resolution; provided such corporation meets the qualifications of each Electric Revenue Bond Resolution.

**Certain Covenants (Article VII)**

Energy Northwest covenants and agrees with the purchasers and owners of all Electric Revenue Bonds issued pursuant to the Electric Revenue Bond Resolution to the following:

*Concerning the Agreements*. So long as any of the Electric Revenue Bonds are Outstanding, Energy Northwest will not (i) voluntarily consent to or permit any rescission of or consent to any amendment to or otherwise take any action under or in connection with any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds, or (ii) voluntarily consent to or permit any rescission of or consent to any amendment to or modification of or otherwise take any action under or in connection with, each Project Agreement in the case of Columbia, each Assignment Agreement, each Property Disposition Agreement or each 1989 Letter Agreement which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds; and Energy Northwest shall perform all of its obligations under said Agreements and shall take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Electric Revenue Bonds afforded by the provisions of said Agreements.

*Encumbrance or Disposition of Project Properties; Termination of Projects*. Energy Northwest will not sell, mortgage, lease or otherwise dispose of any properties of the related Project, or permit the sale, mortgage, lease or other disposition thereof, except as provided below.

(i) Energy Northwest may sell, lease or otherwise dispose of all or any portion of the works, plants and facilities of a Project and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operation of a Project, provided, however, that if the original costs of the properties so to be disposed of was in excess of $5,000,000, an Engineer shall first certify that the properties to be disposed of are unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operations of a Project; provided, however, no such certification shall be required if such sale or other disposition takes place after a Project has been terminated. Money received by Energy Northwest as the proceeds of any such sale, lease or other disposition of all or any portion of the properties of a Project shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds; provided, however, that if such sale, lease or other disposition of all or any portion of the properties of a Project is in connection with the replacement of such properties, all moneys received from such partial disposition of property may be transferred to the respective General Revenue Funds.

(ii) Energy Northwest may sell, lease or otherwise dispose of fuel for a price not less than the lesser of the cost to Energy Northwest thereof or the fair market value thereof at the time of such sale, lease or other disposition; provided, that any moneys received by Energy Northwest as proceeds of any such sale, lease or purchase shall be either transferred to the respective General Revenue Funds or used for the purchase or redemption of Electric Revenue Bonds.

(iii) In the event that the ownership of the properties of a Project or any part thereof shall be transferred from Energy Northwest through the operation of law, any moneys received by Energy Northwest as a result of any such transfer shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds.

(iv) Energy Northwest may terminate a Project at any time. Any moneys received by Energy Northwest from the disposition of the properties of a Project so terminated may be applied to the payment of the cost of decommissioning such Project including the cost of restoring the site thereof, and any amounts so received not required to pay such costs shall be applied as provided in paragraph (iii) above or in each Electric Revenue Bond Resolution.

Nothing contained in the Electric Revenue Bond Resolutions shall be construed to prevent Energy Northwest from constructing as a separate utility system any additional generating unit or units on or near the site of any Project, and using facilities of a Project in connection with the construction or operation therewith without compensation therefor; provided, however, that an Engineer shall certify to Energy Northwest and the Trustee that such use will not adversely affect the operations of the applicable Project or interfere with the performance by Energy Northwest of its obligations under the Electric Revenue Bond Resolutions; and provided further, however, that any compensation received by Energy Northwest on account of any such use shall be paid into the respective General Revenue Funds.

Notwithstanding the provisions of subsections (i) through (iv) above, moneys received by Energy Northwest as a result of any sale, lease, transfer or other disposition specified in such subsections and which are in excess of the amounts required for decommissioning and site restoration costs may be transferred to such funds or accounts determined by Energy Northwest or used to purchase or redeem Electric Revenue Bonds.

*Insurance*. Energy Northwest shall, to the extent available at reasonable cost with responsible insurers, keep, or cause to be kept, the works, plants and facilities comprising the properties of the related Project and the operation thereof insured, with policies payable to Energy Northwest for the benefit of Energy Northwest, the Participants and Bonneville, as their interests may appear, against risks of direct physical loss, damage to or destruction of such properties or any part thereof, and against accidents, casualties, or negligence, including liability insurance and employer's liability, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and such other insurance as may be agreed upon by the parties to the Columbia Project Agreement. In the case of loss, including loss of revenue, caused by suspension or interruption of generation or transmission of power and energy by a Project, the proceeds of any insurance policy or policies covering such loss received by Energy Northwest shall be paid into the related General Revenue Fund. Within 60 days after the end of each fiscal year, Energy Northwest shall file, or cause to be filed, with the Trustee a certificate of an Engineer describing in reasonable detail the insurance on the Projects then in effect pursuant to the requirements of the related Electric Revenue Bond Resolution and stating whether, in its opinion, such insurance then in effect reasonably complies with the provisions hereof.

*Books of Account; Annual Audit*. Energy Northwest shall keep proper books of account for each Project, showing as a separate utility system the accounts of each Project in accordance with the rules and regulations prescribed by any governmental agency authorized to prescribe such rules, including the Division of Municipal Corporations of the State Auditor's office of the State of Washington, or other state department or agency succeeding to such duties of the State Auditor's office, and in accordance with the Uniform System of Accounts prescribed from time to time by the Federal Energy and Regulatory Commission, or any successor federal agency having jurisdiction over electric public utility companies owning and operating properties similar to each Project, whether or not Energy Northwest is required by law to use such system of accounts. Within 120 days after the end of each fiscal year, Energy Northwest shall cause such books of account to be audited by independent certified public accountants of national reputation licensed, registered or entitled to practice and practicing as such under the laws of the State of Washington who, or each of whom, is in fact independent and does not have any interest, direct or indirect, in any contract with Energy Northwest other than his contract of employment to audit books of account of Energy Northwest, and who is not connected with Energy Northwest as an officer or employee of Energy Northwest. A copy of each audit report, annual balance sheet and income and expense statement showing in reasonable detail the financial condition of each Project as of the close of each fiscal year and summarizing in reasonable detail the income and expenses for such year, including the transactions relating to the funds and accounts and the amounts expended for maintenance and for renewals, replacements and gross capital additions to each Project shall be filed promptly with the Trustee and sent to any Bondholder filing with Energy Northwest a written request for a copy thereof. In connection with each annual audit the independent auditor will prepare a report that states nothing came to their attention that caused them to believe that Energy Northwest failed to comply with the terms, covenants, provisions, or conditions of the Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution insofar as they relate to accounting matters or, if not in compliance therewith, the details of such failure to comply.

*Consulting Engineer*. So long as Energy Northwest owns and operates the Columbia Generating Station, Energy Northwest will retain on its staff one or more qualified engineers and hire an independent engineering firm when and as deemed necessary or advisable to provide immediate and continuous engineering counsel with respect to the Columbia Generating Station.

*Protection of Security; Additional Parity Indebtedness*. Energy Northwest is duly authorized under all applicable laws to create and issue the Electric Revenue Bonds and to adopt the Electric Revenue Bond Resolutions and to pledge the revenues and other moneys, securities and funds purported to be pledged by the Electric Revenue Bond Resolutions in the manner and to the extent provided in the Electric Revenue Bond Resolutions. The revenues and other moneys, securities and funds so pledged are and will be free and clear of any pledge, lien, charge or encumbrance thereon, or with respect thereto, prior to, or of equal rank with, the pledge created by the Electric Revenue Bond Resolutions. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

Energy Northwest will not hereafter create any other special fund or funds for the payment of bonds, warrants or other obligations or issue any bonds, warrants or other obligations payable out of or secured by a pledge of revenues or create any additional obligations which will rank on a parity with or in priority over the pledge and lien of such revenues created under the Electric Revenue Bond Resolutions, except that Energy Northwest may issue bonds, notes or other obligations, under a separate resolution or resolutions, which are payable from or secured by a pledge of the revenues and may create or cause to be created any lien or charge on such revenues, ranking on a parity with the pledge and lien created by the Electric Revenue Bond Resolutions, for any one or more of the purposes provided in the Electric Revenue Bond Resolutions or may create Parity Reimbursement Obligations. However, Energy Northwest shall not issue any such additional bonds, notes or other obligations or create Parity Reimbursement Obligations unless, on the date of issue of such bonds, the certain contracts or agreements described in the Electric Revenue Bond Resolutions are in full force and effect and no Event of Default under the Electric Revenue Bond Resolutions shall have occurred and be continuing.

*Further Assurances*. Energy Northwest will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights, revenues and other funds pledged or assigned to the payment of the obligations issued by Energy Northwest payable from the revenues of each Project, including the Electric Revenue Bonds or intended so to be, or which Energy Northwest may hereafter become bound to pledge or assign.

*Tax Covenants*. Energy Northwest covenants with the owners from time to time of the Electric Revenue Bonds that (i) throughout the term of the Electric Revenue Bonds, and (ii) through the date that the final rebate, if any, must be made to the United States in accordance with Section 148 of the Code it will comply with the provisions of Sections 103 and 141 through 150 of the Code and all regulations proposed and promulgated thereunder that must be satisfied in order that interest on the Electric Revenue Bonds shall be and continue to be excluded from gross income for federal income tax purposes.

Energy Northwest shall not permit at any time or times any of the proceeds of the Electric Revenue Bonds or any other funds of Energy Northwest to be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Electric Revenue Bond to be an "arbitrage bond" as defined in Section 148 of the Code, or any successor provision of law.

Energy Northwest shall not permit at any time or times any proceeds of any Series of Electric Revenue Bonds or any other funds of Energy Northwest to be used, directly or indirectly, in a manner which would result in the exclusion of any Electric Revenue Bond from the treatment afforded by Section 103(a) of the Code.

Anything contained in the three preceding paragraphs to the contrary notwithstanding, Energy Northwest reserves the right to issue, from time to time, one or more Series of Electric Revenue Bonds the interest on which is includable in the gross income of the recipient thereof for federal income tax purposes ("Taxable Bonds"), provided that the issuance of any such Series of Taxable Bonds does not adversely affect the federal tax exemption of the interest on any other Series of Electric Revenue Bonds.

**Events of Default and Remedies (Section 801)**

The occurrence of one or more of the following events shall constitute an "Event of Default" under the Electric Revenue Bond Resolution to which such Event of Default relates:

(1) if payment of principal or the redemption price of any related Electric Revenue Bond shall not punctually be made when due and payable, whether at the stated maturity thereof, upon redemption or otherwise;

(2) if payment of the interest on any related Electric Revenue Bond shall not punctually be made when due;

(3) if payment of any related Parity Reimbursement Obligation shall not be punctually made when due;

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed, and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected;

(5) if an order, judgment, or decree shall be entered by any court of competent jurisdiction, with the consent or acquiescence of Energy Northwest, or if such order, judgment or decree, having been entered without the consent or acquiescence of Energy Northwest, shall not be vacated or set aside or discharged or stayed (or in case custody or control is assumed by said order, such custody or control shall not otherwise be terminated) within ninety (90) days after the entry thereof, and if appealed, shall not thereafter be vacated or discharged: (i) appointing a receiver, trustee or liquidator for Energy Northwest; or (ii) assuming custody or control of the whole or any substantial part of the applicable Project under the provisions of any law for the relief or aid of debtors; or (iii) approving a petition filed against Energy Northwest under the provisions of 11 USC 901-946, as amended (the "Bankruptcy Act"); or (iv) granting relief to Energy Northwest under any amendment to said Bankruptcy Act, or under any other applicable Bankruptcy Act, which shall give relief substantially similar to that afforded by Chapter IX thereof; and

(6) if Energy Northwest shall (i) admit in writing its inability to pay its debts generally as they become due; or (ii) file a petition in bankruptcy or seeking a composition of indebtedness; or (iii) make an assignment for the benefit of its creditors; or (iv) file a petition or any answer seeking relief under the Bankruptcy Act referred to in the preceding clause, or under any amendment thereto, or under any other applicable bankruptcy act which shall give relief substantially the same as that afforded by Chapter IX of said act; or (v) consent to the appointment of a receiver of the whole or any substantial part of the applicable Project; or (vi) consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of Energy Northwest or of the whole or any substantial part of the applicable Project.

Upon the occurrence of an Event of Default described in the preceding paragraphs, and in each and every such case, so long as such Event of Default shall not have been remedied, unless the principal of all the related Electric Revenue Bonds shall have already become due and payable, the Trustee may, and upon the written request of the owners of not less than 25% of all related Electric Revenue Bonds then outstanding shall, proceed to enforce by such proceedings at law or in equity as it deems most effectual the rights of related Bondholders, and either the Trustee (by notice in writing to Energy Northwest), or the owners of not less than 25% in principal amount of the related Electric Revenue Bonds outstanding (by notice in writing to Energy Northwest and the Trustee), may declare the principal of all the related Electric Revenue Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable. The Trustee shall not be obligated to notify Energy Northwest of its intent to make such a declaration prior to making such declaration. The right of the Trustee or of the owners of not less than 25% in principal amount of the related Electric Revenue Bonds to make any such declaration, however, shall be subject to the condition that if, at any time after such declaration, but before the related Electric Revenue Bonds shall have matured by their terms, all overdue installments of interest upon the related Electric Revenue Bonds, together with interest on such overdue installments of interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee (including reasonable fees and expenses of counsel to the Trustee), and all other sums then payable by Energy Northwest under the related Electric Revenue Bond Resolution (except the principal of, and interest accrued since the next preceding Payment Date on, the related Electric Revenue Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the related Electric Revenue Bonds or under the related Electric Revenue Bond Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be cured or provision shall be made therefor, then and in every such case the owners of a majority in principal amount of the related Electric Revenue Bonds outstanding, by written notice to Energy Northwest and to the Trustee, may rescind such declaration and annul such default in its entirety, or, if the Trustee shall have acted itself, and if there shall not have been theretofore delivered to the Trustee written directions to the contrary by the owners of a majority in principal amount of the related Electric Revenue Bonds then outstanding, then any such declaration shall ipso facto be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any resulting right or power.

**Notice to Bondholders of an Event of Default (Section 802)**

The Trustee, within 25 days after the occurrence of an Event of Default, shall give to the Bondholders of the related Electric Revenue Bonds, in the manner provided in the applicable Electric Revenue Bond Resolution, notice of all defaults known to the Trustee, and shall give prompt written notice thereof to Energy Northwest, unless such defaults shall have been cured before the giving of such notice.

**Accounting and Examination of Records after Default (Section 803)**

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and account of Energy Northwest relating to the related Project and all other records relating thereto shall at all times be subject to the inspection and use of the Trustee and any persons holding at least 25% of the principal amount of the related Electric Revenue Bonds outstanding and of their respective agents and attorneys or of any committee therefor.

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, Energy Northwest will continue to account, as a trustee of an express trust, for all revenues and other moneys, securities and funds pledged under the related Electric Revenue Bond Resolution.

**Application of Revenues in an Event of Default (Section 804)**

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution.

During the continuance of an Event of Default, the revenues and other moneys of the related Project received by the Trustee shall be applied by the Trustee: first, to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the related Project, including the costs of decommissioning and site restoration, if any, and all other proper disbursements or liabilities made or incurred by the Trustee (including the fees and expenses of counsel to the Trustee); and second, to the then due and overdue payments into the related Debt Service Fund and the due and overdue payments on any related Parity Reimbursement Obligations and the due and overdue payments of any other obligation of Energy Northwest for which the Revenues are pledged on a parity with the pledge under Section 202(a) of the related Electric Revenue Bond Resolution pursuant to a Supplemental Electric Revenue Bond Resolution ("Other Parity Obligations"); and lastly, for any lawful purpose in connection with the related Project.

In the event that at any time the funds held by the Trustee shall be insufficient for the payment of the principal of, premium, if any, and interest then due on the related Electric Revenue Bonds and payments then due on any related Parity Reimbursement Obligations and Other Parity Obligations, such funds (other than funds held for the payment or redemption of particular Electric Revenue Bonds or Parity Reimbursement Obligations or Other Parity Obligations, including, without limiting the generality of the foregoing, amounts held in any Reserve Account for a particular Series of Electric Revenue Bonds) and all revenues of Energy Northwest and other moneys received or collected for the benefit or for the account of owners of the Electric Revenue Bonds and any Parity Reimbursement Obligations and Other Parity Obligations by the Trustee shall be applied as follows:

(1) Unless the principal of all of the related Electric Revenue Bonds shall have become due and payable,

*First*, to the payment of all necessary and proper operating expenses of the applicable Project and all other proper disbursements or liabilities made or incurred by the Trustee;

*Second*, to the payment to the persons entitled thereto of all installments of interest then due on the related Electric Revenue Bonds (including any interest on overdue principal) in the order of the maturity of such installments, earliest maturities first, and on any related Parity Reimbursement Obligations and Other Parity Obligations and if the amounts available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

*Third*, to the payment to the persons entitled thereto of the principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at the time of such payment without preference or priority of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, and if the amounts available therefor shall not be sufficient to pay in full any principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at such time, then to the payment thereof, ratably, according to the amounts due respectively for principal and redemption premium, without any discrimination or preference.

(2) If the principal of all of the related Electric Revenue Bonds shall have become due and payable,

*First*, to the payment of all necessary and proper operating expenses of the related Project and all other proper disbursements or liabilities made or incurred by the Trustee; and

*Second*, to the payment of the principal and interest then due and unpaid upon the related Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Whenever moneys are to be applied as described in the preceding paragraphs, such moneys shall be applied by the Trustee, at such times, and from time to time, as it in its sole discretion shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future.

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its money, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

**Remedies Not Exclusive (Section 809)**

No remedy by the terms of either of the Electric Revenue Bond Resolutions conferred upon or reserved to the owners of the related Electric Revenue Bonds is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to any other remedy given to the owners of the related Electric Revenue Bonds or now or hereafter existing at law or in equity or by statute.

**Waivers of Default (Section 810)**

No delay or omission of any owner of Electric Revenue Bonds to exercise any right or power arising upon the occurrence of a default hereunder, including an Event of Default, will impair any right or power or shall be construed to be a waiver of any such default or to be an acquiescence therein. Every power and remedy given by this Article to the Trustee or to the owners of Electric Revenue Bonds may be exercised from time to time and as often as may be deemed expedient by such Trustee or by such owners.

Prior to the declaration of acceleration of the Electric Revenue Bonds as provided in Section 801, the holders of a majority in principal amount of the Electric Revenue Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the holders of all the Electric Revenue Bonds waive any past default under this Resolution and its consequences, except a default described in paragraph (1), (2), (3), or (4) of Section 801. No such waiver will extend to any subsequent or other default or impair any right consequent thereon.

**Supplemental Electric Revenue Bond Resolutions (Article IX)**

*Supplemental Electric Revenue Bond Resolutions Effective Without Consent of Owners of Electric Revenue Bonds*. Energy Northwest, from time to time and at any time and without the consent or concurrence of any owner of any Electric Revenue Bond, may adopt a resolution amendatory of each Electric Revenue Bond Resolution or supplemental to each Electric Revenue Bond Resolution (i) for the purpose of providing for the issuance of Electric Revenue Bonds pursuant to the provisions of Article II of each Electric Revenue Bond Resolution, or (ii) if the provisions of such Supplemental Electric Revenue Bond Resolutions shall not adversely affect the rights of the owners of the Electric Revenue Bonds of each Series or, if a Series consists of two or more subseries, of each subseries thereof, affected by such Supplemental Electric Revenue Bond Resolutions then outstanding, for any one or more of the following purposes:

(1) to make any changes or corrections in the Electric Revenue Bond Resolutions as to which Energy Northwest shall have been advised by counsel that the same are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provision or omission or mistake or manifest error contained in the Electric Revenue Bond Resolutions, or to insert in the Electric Revenue Bond Resolutions such provisions clarifying matters or questions arising under the Electric Revenue Bond Resolutions as are necessary or desirable;

(2) to add additional covenants and agreements of Energy Northwest for the purpose of further securing the payment of the Electric Revenue Bonds;

(3) to surrender any right, power or privilege reserved to or conferred upon Energy Northwest by the terms of the Electric Revenue Bond Resolutions;

(4) to confirm as further assurance any lien, pledge or charge, or the subjection to any lien, pledge, or charge, created or to be created by the provisions of the Electric Revenue Bond Resolutions;

(5) to grant or to confer upon the owners of the Electric Revenue Bonds any additional rights, remedies, powers, authority or security that lawfully may be granted to or conferred upon them, or to grant to or to confer upon the Trustee for the benefit of the owners of the Electric Revenue Bonds any additional rights, duties, remedies, powers, authority or security or to provide for one or more Credit Facilities;

(6) to make any appointment or to add any provision, in either case, required or permitted by the Electric Revenue Bond Resolutions to be so made or added pursuant to a Supplemental Electric Revenue Bond Resolution;

(7) to enter into Payment Agreements; and

(8) to make any other change which Energy Northwest deems necessary or desirable and which does not adversely affect the rights of the Bondholders.

*Supplemental Electric Revenue Bond Resolutions Effective With Consent of Bondholders*. At any time, Supplemental Electric Revenue Bond Resolutions may be adopted subject to consent by Bondholders in accordance with and subject to the provisions of each Electric Revenue Bond Resolution, which Supplemental Electric Revenue Bond Resolutions, upon the filing with the Trustee of a copy thereof certified by an authorized officer of Energy Northwest and upon compliance with the provisions of Article X of each Electric Revenue Bond Resolution, shall become fully effective in accordance with its terms as provided in said Article.

**Powers of Amendment (Section 1002)**

Any modification or amendment of the Electric Revenue Bond Resolutions or of the rights and obligations of Energy Northwest and of the owner of the Electric Revenue Bonds thereunder, in any particular, may be made by Supplemental Electric Revenue Bond Resolutions, with the written consent given as provided in each Electric Revenue Bond Resolution, (i) of the owners of not less than a majority in principal amount of the related Electric Revenue Bonds outstanding at the time such consent is given, and (ii) in case less than all of the several Series of Electric Revenue Bonds or, if any Series consists of two or more subseries, the subseries thereof, then outstanding are affected by the modification or amendment, of the owners of not less than a majority in principal amount of the Electric Revenue Bonds of such Series or subseries, as the case may be, so affected and outstanding at the time such consent is given; except that if such modification or amendment will, by its terms, not take effect so long as any Electric Revenue Bonds of any specified like Series, subseries, if applicable, and maturity remain outstanding, the consent of the owners of such Electric Revenue Bonds shall not be required and such Electric Revenue Bonds shall not be deemed to be outstanding for the purpose of any calculation of outstanding Electric Revenue Bonds under this provision of each Electric Revenue Bond Resolution. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any outstanding Electric Revenue Bond or of any installment of interest thereon or a reduction in the principal amount or the redemption price thereof or in the rate of interest thereon without the consent of the owner of such Electric Revenue Bond, or shall reduce the percentages or otherwise affect the classes of Electric Revenue Bonds the consent of the owners of which is required to effect any such modification or amendment, or permit a preference or priority of any Electric Revenue Bond over any other or shall change or modify any of the rights or obligations of any fiduciary without its written assent thereto. For the purposes of this provision of each Electric Revenue Bond Resolution, a Series or subseries, as the case may be, shall be deemed to be affected by a modification or amendment of each Electric Revenue Bond Resolution if the same adversely affects or diminishes the rights of the owners of Electric Revenue Bonds of such Series or subseries, respectively. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment of the Electric Revenue Bonds of any particular Series, Subseries, if applicable, or maturity would be affected by any modification or amendment of the Electric Revenue Bond Resolutions and any such determination shall be binding and conclusive on Energy Northwest and all owners of Electric Revenue Bonds. For the purposes of this Section, the owners of the Electric Revenue Bonds may include the initial owners thereof, regardless of whether such Electric Revenue Bonds are being held for immediate resale.

**Defeasance (Article XI)**

Except as otherwise provided in each Supplemental Electric Revenue Bond Resolution authorizing the issuance of variable rate Electric Revenue Bonds, the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in such Electric Revenue Bond Resolutions, shall be fully discharged and satisfied as to any related Electric Revenue Bond and such related Electric Revenue Bond shall no longer be deemed to be outstanding hereunder,

(i) when such related Electric Revenue Bond shall have been canceled, or shall have been surrendered for cancellation or is subject to cancellation, or shall have been purchased by the Trustee from moneys held under the related Electric Revenue Bond Resolutions; or

(ii) as to any related Electric Revenue Bond not canceled or surrendered for cancellation or subject to cancellation or so purchased, when payment of the principal of and premium, if any, on such related Electric Revenue Bond, plus interest on such principal to the due date thereof (whether such due date be by reason of maturity or upon redemption or prepayment, or otherwise) either (A) shall have been made or caused to be made in accordance with the terms thereof, or (B) shall have been provided for by irrevocably depositing with the trustee or a paying agent for such Electric Revenue Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) Defeasance Obligations maturing, or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will insure the availability of sufficient moneys to make such payment, or a combination thereof, whichever Energy Northwest deems to be in its best interest, and all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to the Electric Revenue Bond with respect to which such deposit is made shall have been paid or the payment thereof provided for to the satisfaction of the Trustee and said paying agents.

At such time as an Electric Revenue Bond shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, such Electric Revenue Bond shall no longer be secured by or entitled to the benefits of the related Electric Revenue Bond Resolution, except for the purposes of any payment from such moneys or Defeasance Obligations.

Notwithstanding the foregoing, in the case of an Electric Revenue Bond which is to be redeemed or otherwise prepaid prior to its stated maturity, no deposit under clause (B) of subparagraph (ii) above shall constitute such payment, discharge and satisfaction as aforesaid until such Electric Revenue Bond shall have been irrevocably designated for redemption or prepayment and proper notice of such redemption or prepayment shall have been previously published in accordance with each Electric Revenue Bond Resolution or in accordance with the provisions of the Supplemental Electric Revenue Bond Resolutions which authorized the issuance of the Electric Revenue Bonds being refunded or provision satisfactory to the Trustee shall have been irrevocably made for the giving of such notice.

Any such moneys so deposited with the trustee or paying agents for the Electric Revenue Bonds as provided in the Electric Revenue Bond Resolutions may at the direction of Energy Northwest also be invested and reinvested in Defeasance Obligations, maturing in the amounts and times as hereinbefore set forth. All income from all Defeasance Obligations in the hands of the trustee or paying agents which is not required for the payment of the Electric Revenue Bonds and interest and premium thereon with respect to which such moneys shall have been so deposited, shall be paid to Energy Northwest for deposit in the respective General Revenue Funds. Likewise, whenever all of the Electric Revenue Bonds of a Series shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, as aforesaid, the amounts, if any, remaining on deposit to the credit of the Reserve Accounts established for such Series shall be paid to Energy Northwest for deposit in the respective General Revenue Funds.

Any provision contained in the Electric Revenue Bond Resolutions to the contrary notwithstanding, all moneys and Defeasance Obligations set aside and held in trust for the payment of Electric Revenue Bonds shall be applied to and used solely for the payment of the particular Electric Revenue Bond with respect to which such moneys and Defeasance Obligations have been so set aside in trust.

Notwithstanding anything in the Electric Revenue Bond Resolutions to the contrary, if moneys or Defeasance Obligations have been deposited or set aside with the trustee or a paying agent for the payment of a specific Electric Revenue Bond and such Electric Revenue Bond shall be deemed to have been paid and to be no longer outstanding, but such Electric Revenue Bond shall not have in fact been actually paid in full, no amendment to the provisions of either of the Electric Revenue Bond Resolutions shall be made without the consent of the owner of each Electric Revenue Bond affected thereby.

Energy Northwest may at any time surrender to the Trustee for cancellation by it any Electric Revenue Bonds previously executed and delivered, which Energy Northwest may have acquired in any manner whatsoever, and such Electric Revenue Bonds upon such surrender for cancellation shall be deemed to be paid and no longer outstanding under either of the Electric Revenue Bond Resolutions.

Neither the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions, nor any Supplemental Resolutions authorizing Parity Reimbursement Obligations and/or Other Parity Obligations, shall be discharged or satisfied with respect to such Parity Reimbursement Obligations or Other Parity Obligations, respectively, until such Parity Reimbursement Obligations shall have been paid in accordance with their terms.

**Summary of the Supplemental Electric Revenue Bond Resolutions**

*Debt Service Account*. Each Supplemental Electric Revenue Bond Resolution creates and establishes a special trust account of the Debt Service Fund which shall be held by the Trustee subject to the lien of the related Project's Electric Revenue Bond Resolution. The Debt Service Accounts shall be funded as provided in the related Electric Revenue Bond Resolution and amounts therein shall be used and applied as provided in the related Supplemental Electric Revenue Bond Resolution and in the related Electric Revenue Bond Resolution.

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**BOOK-ENTRY SYSTEM**

*The following information (except for the final paragraph) has been provided by the Depository Trust Company, New York, New York ("DTC"). Energy Northwest makes no representation regarding the accuracy or completeness thereof. Beneficial Owners (as hereinafter defined) should therefore confirm the following with DTC or the DTC Participants (as hereinafter defined).*

DTC will initially act as securities depository for the Series 2023-A Bonds. The Series 2023-A Bonds will be issued as fully-registered securities 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 2023-A Bond certificate will be issued for each maturity of the Series 2023-A Bonds, in the principal amount of such maturity, and will be deposited with DTC.

DTC 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, as amended. 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 of 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. More information about DTC can be found at www.dtcc.com.

Purchases of the Series 2023-A Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the Series 2023-A Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2023-A 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 beneficial ownership interests in the Series 2023-A 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 beneficial ownership interests in the Series 2023-A Bonds, except in the event that use of the book-entry system for the Series 2023-A Bonds is discontinued.

To facilitate subsequent transfers, all Series 2023-A 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 Series 2023-A 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 2023-A Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2023-A 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.

When notices are given, they shall be sent by the Bond Registrar to DTC only. 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.

Redemption notices will be sent to DTC. If less than all of the Series 2023-A Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities, including any sinking fund redemptions of Term Bonds, to be redeemed. If less than all of the Series 2023-A Bonds of any maturity are to be redeemed, the Series 2023-A Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Series 2023-A Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Energy Northwest 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 Series 2023-A Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the Series 2023-A 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 Energy Northwest or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Bond Registrar, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Bond Registrar, 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 2023-A Bonds at any time by giving reasonable notice to Energy Northwest or the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2023-A Bond certificates are required to be printed and delivered.

Energy Northwest may decide to discontinue use of the system of book-entry only transfers through DTC (or a successor securities depository). In that event, Series 2023-A Bonds will be printed and delivered.

For so long as the Series 2023-A Bonds are registered in the name of DTC or its nominee, Cede & Co., Energy Northwest and the Bond Registrar will recognize only DTC or its nominee, Cede & Co., as the registered owner of the Series 2023-A Bonds for all purposes, including payments, notices and voting. So long as Cede & Co. is the registered owner of the Series 2023-A Bonds, references in this Official Statement to registered owners of the Series 2023-A Bonds shall mean Cede & Co. and shall not mean the Beneficial Owners of the Series 2023-A Bonds.

Because DTC is treated as the owner of the Series 2023-A Bonds for substantially all purposes, Beneficial Owners may have a restricted ability to influence in a timely fashion remedial action or the giving or withholding of requested consents or other directions. In addition, because the identity of Beneficial Owners is unknown to Energy Northwest or DTC, it may be difficult to transmit information of potential interest to Beneficial Owners in an effective and timely manner. Beneficial Owners should make appropriate arrangements with their broker or dealer regarding distribution of information regarding the Series 2023-A Bonds that may be transmitted by or through DTC.

Energy Northwest will have no responsibility or obligation with respect to: (i) the accuracy of the records of DTC, its nominee or any Direct Participant or Indirect Participant with respect to any Beneficial Ownership interest in the Series 2023-A Bonds; (ii) the delivery to any Direct Participant or Indirect Participant or any other person, other than a registered owner as shown in the Bond Register, of any notice with respect to the Series 2023-A Bonds including, without limitation, any notice of redemption with respect to the Series 2023-A Bonds; (iii) the payment to any Direct Participant or Indirect Participant or any other person, other than a registered owner as shown in the Bond Register, of any amount with respect to the principal of, premium, if any, or interest on, the Series 2023-A Bonds; (iv) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the Series 2023-A Bonds; (v) any consent given or action taken by DTC or its nominee as registered owner; or (vi) any other matter.

Prior to any discontinuation of the book-entry only system hereinabove described, Energy Northwest and the Bond Registrar may treat Cede & Co. (or such other nominee of DTC) as, and deem Cede & Co. (or such other nominee) to be, the absolute registered owner of the Series 2023-A Bonds for all purposes whatsoever, including, without limitation: (a) the payment of principal, premium, if any, and interest on the Series 2023-A Bonds; (b) giving notices of redemption and other matters with respect to the Series 2023-A Bonds; (c) registering transfers with respect to the Series 2023-A Bonds; and (d) the selection of Series 2023-A Bonds for redemption.

## SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville entered into written agreements (the "Disclosure Agreements") for the benefit of the holders and beneficial owners of the Series 2023-A Bonds to provide continuing disclosure.

**Definitions.**

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreements, which apply to any capitalized term used in the Disclosure Agreements, the following capitalized terms shall have the following meanings:

"*BPA Annual Information*" means financial information and operating data generally of the type included in the final Official Statement for the Series 2023-A Bonds in the following tables in Appendix A under the headings "POWER SERVICES": "Bonneville Power Services' Ten Largest Customers by Sales" and "Historical Average PF Preference Rates," "TRANSMISSION SERVICES": "Transmission Services' Ten Largest Customers By Sales," "BONNEVILLE FINANCIAL OPERATIONS": "Historical Capital Spending by Program by Fiscal Year," "Historical Capital Funding by Source and Fiscal Year," "Bonneville's Fiscal Year-End Financial Reserves," "Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow," "Federal System Statement of Revenues and Expenses," and "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments."

"*Energy Northwest Annual Information*" means financial information and operating data generally of the type included in the final Official Statement for the Series 2023-A Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of March 31, 2023" under the heading "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" and in the table labeled "Statement of Operations" under the heading "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION —Annual Costs."

"*Energy Northwest Fiscal Year*" means the fiscal year ending each June 30 or, if such fiscal year end is changed, on such new date; provided that if the Energy Northwest Fiscal Year end is changed, Energy Northwest shall provide written notice of such change to the MSRB.

"*FCRPS*" means the Federal Columbia River Power System.

"*FCRPS Fiscal Year*" shall mean 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.

"*MSRB*" means the Municipal Securities Rulemaking Board or any successors to its functions.

"*Rule 15c2-12*" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of this Disclosure Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Disclosure Agreement.

**Financial Information.**

*Bonneville*. Bonneville agrees to provide 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, 2023:

(i) the BPA Annual Information for the FCRPS Fiscal Year;

(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 shall notify Energy Northwest when such BPA Annual Information has been provided and when such financial statements have been provided.

*Energy Northwest*. Energy Northwest agrees to provide to the MSRB, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with the Energy Northwest Fiscal Year ending June 30, 2023:

(i) the Energy Northwest Annual Information for the Energy Northwest Fiscal Year;

(ii) annual financial statements of Energy Northwest for the Energy Northwest Fiscal Year, prepared in accordance with generally accepted accounting principles applicable to governmental entities; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not its audited annual financial statements, Energy Northwest shall provide its audited annual financial statements when and if they become available.

*Cross-Reference*. In lieu of providing the annual financial information and operating data described above, Bonneville and Energy Northwest may specifically cross-reference other documents available to the public on the internet website of the MSRB, or filed with the SEC.

*Notice of Failure to Provide Financial Information*. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to the MSRB (i) notice of Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above and (ii) notice of Energy Northwest's failure to provide the annual financial information described above on or prior to the applicable date set forth above.

**Events Notices.**

Energy Northwest agrees to provide or cause to be provided, in a timely manner (not in excess of ten business days after the occurrence of the event), to the MSRB, notice of the occurrence of any of the following events with respect to the Series 2023-A Bonds:

i. Principal and interest payment delinquencies;

ii. Non-payment related defaults, if material;

iii. Unscheduled draws on debt service reserves reflecting financial difficulties;

iv. Unscheduled draws on credit enhancements reflecting financial difficulties;

v. Substitution of credit or liquidity providers, or their failure to perform;

vi. Adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notice of Proposed Issue (IRS Form 5701 – TEB) or other material notices or determinations with respect to the tax status of the Series 2023-A Bonds;

vii. Modifications to rights of Series 2023-A Bondholders, if material;

viii. Optional, contingent or unscheduled calls of any Series 2023-A Bonds other than scheduled sinking fund redemptions for which notice is given pursuant to Exchange Act Release 34-23856, if material, and tender offers;

ix. Defeasances;

x. Release, substitution or sale of property securing repayment of the Series 2023-A Bonds, if material;

xi. Rating changes;

xii. Bankruptcy, insolvency, receivership or similar event of Energy Northwest (a "Bankruptcy Event");

xiii. The consummation of a merger, consolidation, or acquisition involving Energy Northwest or the sale of all or substantially all of the assets of Energy Northwest, 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;

xiv. Appointment of a successor or additional trustee or the change of name of a trustee, if material;

xv. Incurrence of a financial obligation of Energy Northwest or Bonneville, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a financial obligation of Energy Northwest or Bonneville, any of which affect security holders, if material; and

xvi. Default, event of acceleration, termination event, modification of terms, or other similar events under the terms of the financial obligation of Energy Northwest or Bonneville, any of which reflect financial difficulties.

A Bankruptcy Event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for Energy Northwest 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 Energy Northwest, 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.

The term financial obligation means a (i) debt obligation; (ii) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (iii) guarantee of (i) or (ii). The term financial obligation shall not include municipal securities as to which a final official statement has been provided to the MSRB consistent with Rule 15c2-12.

Solely for purposes of disclosure, and not intending to modify this undertaking, Energy Northwest advises with (i) reference to items (iii) and (x) above that no debt service reserves or property secure payment of the Series 2023-A Bonds, and (ii) reference to items (iv) and (v) above that no credit enhancements or liquidity facilities secure payment of the Series 2023-A Bonds.

**Availability of Information from the MSRB.**

Energy Northwest and Bonneville have agreed to provide the foregoing information only to the MSRB. The information filed with the MSRB is available to the public without charge through an internet portal.

**Termination, Modification.**

The obligations of Bonneville and Energy Northwest to provide annual financial information and the obligation of Energy Northwest to provide timely notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Series 2023-A Bonds. This section, or any provision hereof, shall be null and void if Bonneville and Energy Northwest (i) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule that require this Disclosure Agreement, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the Series 2023-A Bonds; and (ii) notifies the MSRB of such opinion and the cancellation of this Disclosure Agreement.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, Bonneville and Energy Northwest shall describe such amendment in each of their next annual reports, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville or Energy Northwest, as applicable. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the same manner as for a listed event under "Events Notices," and (ii) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

**Remedies.**

The right of any Owner or Beneficial Owner of Series 2023-A Bonds to enforce the provisions of this Disclosure Agreement against Energy Northwest shall be limited to a right to obtain specific enforcement of Energy Northwest's obligations hereunder, and any failure by Energy Northwest to comply with the provisions of this Disclosure Agreement shall not be an event of default under the Resolution or the Supplemental Resolution or with respect to the Series 2023-A Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Disclosure Agreement. Owners and Beneficial Owners of Series 2023-A Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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ENERGY NORTHWEST • PROJECT 1 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2023-A,
COLUMBIA GENERATING STATION ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2023-A AND PROJECT 3 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2023-A

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