NEW ISSUE — BOOK-ENTRY ONLY

Series 2019-A Bonds: *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 2019-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 2019-A Bonds is not a specific preference item for purposes of the federal alternative minimum tax. See "TAX MATTERS—SERIES 2019-A BONDS" herein.*

Series 2019-B (Taxable) Bonds: *In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2019-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, Section 103 of the 1954 Code, or Section 103 of the 1986 Code. See "TAX MATTERS—SERIES 2019-B (TAXABLE) BONDS" herein.*

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 2019-A/B Bonds. See "TAX MATTERS" herein.

ENERGY NORTHWEST

$269,905,000
ENERGY NORTHWEST

$251,575,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A
$18,330,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable)

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

The Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds (together, the "Series 2019-A/B Bonds") are being issued to finance certain additions and improvements to the Columbia Generating Station and refund certain Electric Revenue Bonds issued by Energy Northwest, as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds. Principal of the Series 2019-A/B Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., as Trustee for the Series 2019-A/B Bonds. Interest on the Series 2019-A/B Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2020. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2019-A/B 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 2019-A/B BONDS—GENERAL—Book-Entry System; Transferability and Registration" and Appendix I—"BOOK-ENTRY SYSTEM" herein.

The Series 2019-A/B Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE SERIES 2019-A/B BONDS—REDEMPTION" *herein.*

The Series 2019-A/B 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 2019-A/B 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. The Columbia Generating Station is a separate project of Energy Northwest, and the Series 2019-A/B Bonds are payable solely from the revenues of the Columbia Generating Station. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover Page

The Series 2019-A/B Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Pepper PLLC, 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 2019-A/B Bonds will be available for delivery through the facilities of DTC on or about May 30, 2019.

J.P. Morgan **BofA Merrill Lynch**

Citigroup **Wells Fargo Securities**

May 8, 2019

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

$251,575,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2019-A

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2020	$ 13,390,000	5.000%	1.570%	103.678	29270C2L8
2021	9,255,000	5.000	1.570	107.011	29270C2M6
2022	5,865,000	5.000	1.580	110.260	29270C2N4
2023	4,220,000	5.000	1.590	113.437	29270C2P9
2024	4,430,000	5.000	1.610	116.489	29270C2Q7
2035	25,865,000	5.000	2.330	123.874**	29270C2R5
2036	62,645,000	5.000	2.380	123.368**	29270C2S3
2037	62,850,000	5.000	2.420	122.965**	29270C2T1
2038	63,055,000	5.000	2.460	122.563**	29270C2U8

$18,330,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE REFUNDING BONDS, SERIES 2019-B (TAXABLE)

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2020	$ 220,000	2.400%	2.400%	100.000	29270C2V6
2021	230,000	2.450	2.450	100.000	29270C2W4
2022	240,000	2.480	2.480	100.000	29270C2X2
2023	2,015,000	2.550	2.550	100.000	29270C2Y0
2024	180,000	2.600	2.600	100.000	29270C2Z7
2035	15,445,000	3.457	3.457	100.000	29270C3A1

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* The CUSIP numbers are provided by CUSIP Global Services, managed on behalf of the American Bankers Association by S&P Global Market Intelligence. 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, 2029 par call date.

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

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

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 2019-A/B 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 2019-A/B 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.

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."

IN CONNECTION WITH THE OFFERING OF THE SERIES 2019-A/B BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF THE SERIES 2019-A/B BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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$269,905,000

ENERGY NORTHWEST

$251,575,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A

$18,330,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable)

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 2019-A/B Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the Series 2019-A/B 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 $251,575,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A (the "Series 2019-A Bonds"), and $18,330,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable) (the "Series 2019-B (Taxable) Bonds"). The Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds are collectively referred to herein as the "Series 2019-A/B Bonds."

The Series 2019-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. 1042 adopted on October 23, 1997 (as amended and supplemented, including by Resolution No. 1964 adopted on March 27, 2019, 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, and financing a portion of the costs of issuing the Series 2019-A Bonds. The Series 2019-B (Taxable) Bonds are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution for the purpose of refunding certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, financing costs of issuing the Series 2019-B (Taxable) Bonds and financing a portion of the costs of issuing the Series 2019-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 Series 2019-A/B 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.

Energy Northwest may issue bonds pursuant to the Act and Resolution No. 835, adopted on November 23, 1993 (as amended and supplemented, the "Project 1 Electric Revenue Bond Resolution"). Energy Northwest has indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution, which are referred to herein as 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. Energy Northwest is not issuing any Project 1 Electric Revenue Bonds at this time.

Energy Northwest may issue bonds pursuant to the Act and Resolution No. 838, adopted on November 23, 1993 (as amended and supplemented, the "Project 3 Electric Revenue Bond Resolution," and together with the Columbia Electric Revenue Bond Resolution and the Project 1 Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions"). Energy Northwest has indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, which are referred to herein as the "Project 3 Electric Revenue Bonds," and together with the Columbia Electric Revenue Bonds and the Project 1 Electric Revenue Bonds, are collectively referred to herein as 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. Energy Northwest is not issuing any Project 3 Electric Revenue Bonds at this time.

The Electric Revenue Bonds, including the Series 2019-A/B Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Resolutions are collectively referred to herein as the "Net Billed Bonds."

In December 2017, Energy Northwest obtained a line of credit maturing on June 18, 2019, pursuant to a Loan Agreement dated December 18, 2017, between JPMorgan Chase Bank, National Association and Energy Northwest (the "2017 Loan Agreement"), in the amount of $141,000,000 to finance operation and maintenance expenses of Columbia and debt service payments for outstanding Columbia Electric Revenue Bonds. Energy Northwest's obligation to repay advances under the 2017 Loan Agreement is evidenced by a bond anticipation note (the "2017 Note") authorized and delivered by Energy Northwest pursuant to a Separate Resolution adopted on December 14, 2017. The 2017 Note is secured on a parity with the Columbia Electric Revenue Bonds, including the Series 2019-A/B Bonds, issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Columbia Separate Resolutions. As of April 1, 2019, Energy Northwest has borrowed the full amount of $141,000,000.

In January 2019, Energy Northwest obtained a line of credit maturing on June 30, 2020, pursuant to a Loan Agreement dated January 28, 2019, between Bank of America, N.A. and Energy Northwest (the "2019 Loan Agreement"), in the amount not to exceed $227,000,000 to finance operation and maintenance expenses of Columbia and debt service payments for outstanding Columbia Electric Revenue Bonds. Energy Northwest's obligation to repay advances under the 2019 Loan Agreement is evidenced by a bond anticipation note (the "2019 Note") authorized and delivered by Energy Northwest pursuant to a Separate Resolution adopted on January 23, 2019. The 2019 Note is secured on a parity with the Columbia Electric Revenue Bonds, including the Series 2019-A/B Bonds and the 2017 Note, issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Columbia Separate Resolutions. As of April 30, 2019, Energy Northwest has borrowed $90,000,000 on the 2019 Note, and expects to borrow the full amount of $227,000,000 by June 30, 2019. The 2019 Loan Agreement states that the 2019 Note may be increased to an amount not to exceed $457,420,000 and/or extended for up to 12 additional months if agreed to by Energy Northwest and Bank of America, N.A. Energy Northwest has requested the increased amount for the 2019 Note.

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. In November 2018, Public Utility District No. 1 of Cowlitz County withdrew as a member of Energy Northwest. Energy Northwest now has 27 members, consisting of 22 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 Whatcom County re-joined Energy Northwest in April 2019. 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. Energy Northwest also owns and operates a hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), with a net design electric rating of 27.5 megawatts. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 63 turbines with a maximum generating capacity of approximately 96 megawatts. 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 approximately 75% of the bulk transmission capacity 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 14 million people. Electric power sold by Bonneville accounts for approximately 27% 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 agencies 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 2019-A/B BONDS

The Series 2019-A/B Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Series 2019-A/B 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."

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 Columbia bonds or other debt with a lien on Columbia Generating Station revenues superior to the Columbia Electric Revenue Bonds.

The Series 2019-A/B 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 receipts, income and revenues derived from Columbia secure only the Series 2019-A/B Bonds, other Columbia Electric Revenue Bonds, the 2017 Note, the 2019 Note and other obligations issued pursuant to additional related Columbia Separate Resolutions. Accordingly, the owners of the Series 2019-A/B Bonds 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, 2019, 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 Columbia Electric Revenue Bond Resolution for debt service and for all other purposes of Columbia. These costs also 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 related to Project 1 for debt service and for all other purposes of Project 1 and in the Project 3 Electric Revenue Bond Resolution related to Project 3 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 2019-A/B BONDS

GENERAL

The Series 2019-A/B 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 2019-A/B Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2020, at the rates shown on the inside cover page of this Official Statement. Interest on the Series 2019-A/B 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 2019-A/B Bonds (collectively, the "Trustee"). For so long as the Series 2019-A/B 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 2019-A/B 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 2019-A/B Bonds will not receive certificates representing their interests in such Series 2019-A/B 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 2019-A/B Bonds. As discussed in Appendix I—"BOOK-ENTRY SYSTEM," transfers of ownership interests in the Series 2019-A/B 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 2019-A/B Bonds. Energy Northwest, the Trustee and any other person may treat the registered owner of any Series 2019-A/B Bonds as the absolute owner of such Series 2019-A/B 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 2019-A/B Bonds shall be overdue or not. All payments of or on account of interest or principal to any registered owner of any such Series 2019-A/B 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 2019-A/B Bonds, to the extent of the sum or sums paid.

When Series 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B Bond is registered, as the holder and absolute owner of such Series 2019-A/B 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 2019-A/B Bonds, Series 2019-A/B Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the Series 2019-A/B Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the Series 2019-A/B Bonds will be payable by check or draft mailed to the persons in whose names such Series 2019-A/B 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 2019-A/B 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 2019-A/B Bonds is discontinued, registered ownership of any Series 2019-A/B Bond may be transferred or exchanged by surrendering such Series 2019-A/B Bond to the Trustee, with the assignment form appearing on the Series 2019-A/B Bond duly executed. The Trustee shall not be required to transfer any Series 2019-A/B Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

Series 2019-A Bonds. The Series 2019-A Bonds maturing on and after July 1, 2035, are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2029, 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 2019-A Bonds to be redeemed, plus interest accrued to the date of redemption.

Series 2019-B (Taxable) Bonds. The Series 2019-B (Taxable) Bonds are subject to redemption prior to their respective maturities at the option of Energy Northwest (with the approval of Bonneville), in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The “Make-Whole Redemption Price” is the greater of (1) the issue price as shown on the inside cover page of this Official Statement (but not less than 100% of the principal amount) of the Series 2019-B (Taxable) Bonds to be redeemed, or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2019-B (Taxable) Bonds to be redeemed to the maturity date, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2019-B (Taxable) Bonds are to be redeemed, discounted to the date on which such Series 2019-B (Taxable) Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the “Treasury Rate” (defined below) plus five basis points for the Series 2019-B (Taxable) Bonds maturing in the years 2020 through 2024, inclusive, and 15 basis points for the Series 2019-B (Taxable) Bonds maturing in the year 2035, plus accrued and unpaid interest on the Series 2019-B (Taxable) Bonds to be redeemed on the redemption date.

“Business Day” means a day other than a day on which commercial banks located in Seattle, Washington or New York, New York are required or authorized by law to close.

“Treasury Rate” means, with respect to any redemption date for a particular Series 2019-B (Taxable) Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price (defined below), as calculated by the Designated Investment Banker (defined below).

“Comparable Treasury Issue” means, with respect to any Valuation Date for a redemption date for a particular Series 2019-B (Taxable) Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2019-B (Taxable) Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such Series 2019-B (Taxable) Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any Valuation Date for a redemption date for a particular Series 2019-B (Taxable) Bond, (1) the most recent yield data for the applicable U.S. Treasury maturity index from the Federal Reserve Statistical Release H.15 Daily Update (or any comparable or successor publication) reported, as of 11:00 a.m. New York City time, on the Valuation Date; or (2) if the yield described in (1) above is not reported as of such time or the yield reported as of such time is not ascertainable, the average of five Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or if the Designated Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all such quotations.

"Designated Investment Banker" means one of the Reference Treasury Dealers appointed by Energy Northwest (with the approval of Bonneville).

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

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2019-B (Taxable) Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to Energy Northwest, the Trustee and Bonneville by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

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

Partial Redemption

If less than all of the Series 2019-A/B 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 2019-A Bonds of any maturity are to be redeemed, the Series 2019-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 2019-A/B 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 2019-A/B Bonds for redemption, the Trustee will treat each such Series 2019-A/B Bond as representing that number of such Series 2019-A/B Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2019-A/B Bonds to be redeemed in part by $5,000.

The particular Series 2019-B (Taxable) Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2019-B (Taxable) Bonds are registered in book-entry only form, and so long as DTC or a successor securities depository is the sole registered owner of the Series 2019-B (Taxable) Bonds, if less than all of a maturity of the Series 2019-B (Taxable) Bonds of a maturity are called for redemption, the particular Series 2019-B (Taxable) Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2019-B (Taxable) Bonds are held in book-entry form, the selection for redemption of such Series 2019-B (Taxable) Bonds shall be made in accordance with the operational arrangements of DTC then in effect. It is Energy Northwest's intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between Energy Northwest and the Beneficial Owners be made in accordance with the pro rata pass-through distribution of principal basis described below. However, Energy Northwest can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among registered owners on such basis. If the DTC operational arrangements do not allow for the redemption of the Series 2019-B (Taxable) Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2019-B (Taxable) Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

If the Series 2019-B (Taxable) Bonds are not registered in book-entry only form, any redemption of less than all of a maturity of the Series 2019-B (Taxable) Bonds shall be allocated among the registered owners of such Series 2019-B (Taxable) Bonds as nearly as practicable in proportion to the principal amounts of the Series 2019-B (Taxable) Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2019-B (Taxable) Bonds. This will be calculated based on the following formula:

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

Notice of Redemption

Notice of redemption of any Series 2019-A/B 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 2019-A/B Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2019-A/B Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2019-A/B 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 2019-A/B Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2019-A/B 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 2019-A/B Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee on the redemption date and the Series 2019-A/B 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 2019-A/B Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2019-A/B 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 2019-A/B 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 2019-A/B Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2019-A/B 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 2019-A/B Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any Series 2019-A/B 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 Columbia Electric Revenue Bond Resolution shall be fully discharged and satisfied as to any Series 2019-A/B Bond, and such Series 2019-A/B Bond shall no longer be deemed to be outstanding under the Columbia Electric Revenue Bond Resolution, when payment of principal of and premium, if any, on such Series 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds.

If Energy Northwest defeases any Series 2019-B (Taxable) Bond, such Series 2019-B (Taxable) Bond may be deemed to be retired for federal income tax purposes as a result of the defeasance. In that event, the Beneficial Owner of the Series 2019-B (Taxable) Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the Beneficial Owner's adjusted tax basis in the Series 2019-B (Taxable) Bond. See "TAX MATTERS—SERIES 2019-B (TAXABLE) BONDS."

PURPOSE OF ISSUANCE

The Series 2019-A/B Bonds are being issued for the purpose of financing certain additions and improvements to the Columbia Generating Station, currently refunding $263,930,000 aggregate principal amount of the Columbia Electric Revenue Bonds, and paying the costs of issuing the Series 2019-A/B Bonds.

A portion of the proceeds of the Series 2019-A/B Bonds will be used to refund the following Columbia Electric Revenue Bonds:

Columbia Electric Revenue Bonds to be Currently Refunded:

Series	Amount	Maturity (July 1)	Interest Rate	Redemption Date (July 1)	Redemption Price	CUSIP No.
2009-C	$ 14,305,000	2020	5.000%	2019	100%	29270CUP8
2009-C	6,410,000	2021	4.250	2019	100	29270CUQ6
2009-C	3,650,000	2021	5.000	2019	100	29270CT39
2009-C	1,465,000	2022	4.500	2019	100	29270CT47
2009-C	5,195,000	2022	5.000	2019	100	29270CT54
2009-C	4,980,000	2023	5.000	2019	100	29270CT62
2009-C	2,690,000	2024	4.750	2019	100	29270CT70
2009-C	2,540,000	2024	5.000	2019	100	29270CT88
2011-B	10,595,000	2019	4.190	N/A	N/A	29270CWL5
2011-C	4,600,000	2019	3.550	N/A	N/A	29270CXG5
2012-A	204,245,000	2019	5.000	N/A	N/A	29270CXP5
2015-B	2,850,000	2019	1.817	N/A	N/A	29270CL29
2016-B	405,000	2019	1.650	N/A	N/A	29270CR56

Upon the issuance of the Series 2019-A/B Bonds, Energy Northwest expects to purchase investment securities for the Electric Revenue Bonds to be currently refunded, which Energy Northwest shall deposit in the escrow funds established with the Bond Fund Trustee for the Electric Revenue Bonds pursuant to the escrow agreement between Energy Northwest and the Bond Fund Trustee for such Electric Revenue Bonds to be refunded. At the time of such deposit, Energy Northwest shall direct the Bond Fund Trustee for the Electric Revenue Bonds to be redeemed to give notice of redemption of such Electric Revenue Bonds when and as provided in the Electric Revenue Bond Resolutions.

The accuracy of (1) the arithmetical computations as to the adequacy of the principal of and interest on the investment securities, together with other available funds, to pay the principal or redemption price of the above-referenced Electric Revenue Bonds to be currently refunded to the date of their retirement and (2) the adjusted yields on the investments acquired with the proceeds of the Series 2019-A Bonds will be verified by BLX Group LLC.

SOURCES AND USES OF FUNDS(1)

SOURCES OF FUNDS

Principal of Series 2019-A Bonds	$ 251,575,000
Principal of Series 2019-B (Taxable) Bonds	18,330,000
Original Issue Premium	52,515,101
Total	$ 322,420,101

USES OF FUNDS

Deposit into Construction Account	$ 56,515,672
Deposit with trustee to currently refund Columbia Electric Revenue Bonds	263,376,336
Costs of issuing Series 2019-A/B Bonds (including Underwriters' compensation)	2,528,093
Total	$ 322,420,101

(1) Totals may not add due to rounding.

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Series 2019-A/B 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 Series 2019-A/B 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 Series 2019-A/B 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 Series 2019-A/B 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, 2019, $3,327,525,000 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.

As of March 31, 2019, there were $795,580,000 principal amount of Project 1 Electric Revenue Bonds outstanding. 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.

As of March 31, 2019, there were $914,055,000 principal amount of Project 3 Electric Revenue Bonds outstanding. 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 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 Series 2019-A/B 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 Series 2019-A/B Bonds. See "-NET BILLING AND RELATED AGREEMENTS."

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 Electric Revenue 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. 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 Electric Revenue 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. 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 Series 2019-A/B Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Series 2019-A/B Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest. No Bondholder has a claim on the assets of any Project.

The Series 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the Series 2019-A/B 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 2019-A/B 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 opinion to be delivered by Foster Pepper PLLC, as Bond Counsel, concurrently with the issuance of the Series 2019-A/B Bonds will be subject to such limitations. See Appendix D-1—"PROPOSED FORM OF OPINION OF BOND COUNSEL FOR THE SERIES 2019-A/B BONDS," and Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINION OF BOND COUNSEL FOR THE SERIES 2019-A/B BONDS."

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the Series 2019-A/B 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 2017 Note and the 2019 Note were issued pursuant to 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 2019-A/B 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 2019 BUDGETS" for a list of Participants and their respective shares of the Projects' fiscal year 2019 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 2018.

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 megawatts and 27.5 megawatts, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, which has a maximum generating capacity of 95.9 megawatts. 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, 2018 included in this Official Statement as Appendix C, have been audited by Baker Tilly Virchow Krause, 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, 2019. This table does not include information with respect to the 2017 Note or the 2019 Note. See "INTRODUCTION."

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF MARCH 31, 2019

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Electric Revenue Refunding Bonds	$ 795,580,000
COLUMBIA:	
Electric Revenue and Refunding Bonds	$ 3,327,525,000
PROJECT 3:	
Electric Revenue Refunding Bonds	$ 914,055,000
TOTAL NET BILLED REVENUE BONDS	$ 5,037,160,000
Nine Canyon Wind Project Revenue Bonds[(1)]	$ 78,530,000

(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 currently known as "Regional Cooperation Debt."

An important component of the Regional Cooperation Debt approach has been and is the issuance of Net Billed Bonds to refund outstanding Net Billed Bonds at or before their maturities. These refinancing Net Billed Bonds, which includes the Series 2019-A/B Bonds, increased or are expected to increase the weighted average maturities of outstanding Net Billed Bonds to match more closely the useful lives of facilities at the related Net Billed Projects as expected at the time the facilities were originally financed and to 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. The freed up funds enable Bonneville (i) to repay, earlier than would otherwise occur, 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"), (ii) to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury (together with Federal Appropriations Repayment Obligations, the "Federal Repayment Obligations"), and (iii) to achieve certain other debt management goals. See Appendix A–"THE BONNEVILLE POWER ADMINISTRATION—CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

In 2014 through 2018, Energy Northwest issued approximately $1.9 billion of Electric Revenue Refunding Bonds under the Regional Cooperation Debt approach. These refinancings made available to Bonneville additional funds near the end of its Bonneville Fiscal Years 2014 through 2018, which enabled Bonneville to advance the repayment of an additional $2.5 billion of its Federal Appropriations Repayment Obligations over the amounts Bonneville was scheduled to repay for the related rate period. The amounts prepaid bore interest at a rate higher than the rates of interest on the refunding Net Billed Bonds issued by Energy Northwest in Bonneville Fiscal Years 2014 through 2018, and such prepayments resulted in total debt service savings of approximately $2.2 billion.

Bonneville estimates that the aggregate potential principal amount of refinancing Net Billed Bonds to be issued by Energy Northwest under the Regional Cooperation Debt initiative in Bonneville Fiscal Year 2019 and Bonneville Fiscal Year 2020 (including the Series 2019-A/B Bonds) could exceed $478 million, which when combined with certain other coordinated cash management actions described in Appendix A–"THE BONNEVILLE POWER ADMINISTRATION—CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions," are expected to enable Bonneville to accumulate additional balances in the Bonneville Fund to prepay an additional $250 million in Federal Repayment Obligations over the amounts Bonneville is scheduled to repay in Bonneville Fiscal Years 2019 and 2020. The amounts planned to be prepaid bear interest at a rate higher than the rates of interest on the projected refinancing Net Billed Bonds to be issued by Energy Northwest in Bonneville Fiscal Years 2019 and 2020 and are expected to result in total debt service savings of up to $469 million. There is no assurance that these savings will actually be realized.

In September 2018, the Energy Northwest Board adopted a motion supporting the extension of Regional Cooperation Debt through Energy Northwest's fiscal year (July 1 through June 30) ("Energy Northwest Fiscal Year") 2030. 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 in Bonneville Fiscal Years 2021 through 2030 could approach $3.5 billion. These Regional Cooperation Debt refinancings would 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. The freed up funds would enable Bonneville (1) prepay a portion of its Federal Repayment Obligations or (2) to directly fund Bonneville capital investments.

In December 2017, Energy Northwest entered into the 2017 Loan Agreement to fund a portion of interest expense and operation and maintenance expenses for Columbia through the remainder of Energy Northwest Fiscal Year 2018. To effect the borrowing arrangement, Energy Northwest has issued the Columbia 2017 Note in the not to exceed amount of $141,000,000, which matured on December 18, 2018, but which was extended to June 18, 2019. Debt service on this 2017 Note is payable on parity with the Electric Revenue Bonds for Columbia. This borrowing enabled Bonneville to reduce payments to Energy Northwest in Bonneville Fiscal Year 2018 and accumulate like amounts in the Bonneville Fund in Bonneville Fiscal Year 2018. Bonneville will use the accumulated cash in an amount equal to the amount drawn on the 2017 Note to prepay at the end of Bonneville Fiscal Year 2018 comparatively higher interest Federal Appropriations Repayment Obligations one year earlier than otherwise expected.

In January 2019, Energy Northwest entered into the 2019 Loan Agreement to fund a portion of the debt service payments and operation and maintenance expenses for Columbia through the remainder of Energy Northwest Fiscal Year 2019. To effect the borrowing arrangement, Energy Northwest has issued the 2019 Note in the not to exceed amount of $227,000,000, to mature on June 30, 2020. Debt service on this 2019 Note is payable on parity with the outstanding Columbia Electric Revenue Bonds, including the Series 2019-A/B Bonds. This borrowing will enable Energy Northwest to fund a portion of debt service repayment obligations through July 1, 2019. The 2019 Loan Agreement states that the 2019 Note may be increased to an amount not to exceed $457,420,000 and/or extended for up to 12 additional months if agreed to by Energy Northwest and the 2019 Note purchaser. Repayment of the increased amount of the 2019 Note is expected to occur in October 2019 following the receipt of revenues from Tennessee Valley Authority pursuant to the Tennessee Valley Authority agreement established under the depleted uranium enrichment program. See "—THE COLUMBIA GENERATING STATION—Depleted Uranium Enrichment Program."

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 27, consisting of 22 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 Whatcom County re-joined Energy Northwest in April 2019. 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 26 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; (2) the election and removal of, and establishment of salaries for, the five members of the Executive Board selected from among the members of the Board of Directors; and (3) the selection 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
Sid W. Morrison, Chair	Retired Executive	June 2021
Johnny (Jack) Janda, Vice Chair	Public Utility District Commissioner	June 2022
Linda Gott, Secretary	Public Utility District Commissioner	June 2022
James Moss, Assistant Secretary	Director of Energy, United Association of Plumbers & Pipefitters	June 2022
Arie Callaghan	Public Utility District Commissioner	June 2022
Marc Daudon	Management Consultant	June 2022
Jim Malinowski	Public Utility District Commissioner	June 2022
William (Skip) Orser	Retired Nuclear Executive	June 2022
Will Purser	Public Utility District Commissioner	June 2022
John Saven	Retired Utility Executive	June 2020
Tim Sheldon	Washington State Senator	June 2020

MANAGEMENT

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

Name	Position	Nuclear Industry Experience
Bradley J. Sawatzke	Chief Executive Officer	37 years
William G. Hettel	Chief Nuclear Officer	37 years
Brent J. Ridge	Vice President, Corporate Services and Chief Financial Officer	16 years
Alex L. Javorik	Vice President, Nuclear Engineering	38 years
Robert E. Schuetz	Vice President, Nuclear Operations	39 years
Scott A. Vance	Vice President, General Counsel/Corporate Governance	30 years
David P. Brown	Plant General Manager	26 years
Maurice A. Black	Operations Support General Manager	33 years
Stephen M. Lorence	Corporate Services General Manager	27 years
		Experience
Tim M. Nies	Energy Services and Development General Manager	25 years

EMPLOYEES

As of January 1, 2019, Energy Northwest employed 1,095 employees. Of these employees, 303 are members of the International Brotherhood of Electrical Workers ("IBEW"), 134 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 2019. The Nuclear, USW, HAMTC and Travelers bargaining agreements are in place through 2020. Energy Northwest considers labor relations to be satisfactory.

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.

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 participates in certain retirement plans administered by the State of Washington (the "State"). In addition, Energy Northwest offers a 401(k) Deferred Compensation Plan, a 457 Deferred Compensation Plan 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, 2018, 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, 2018: (1) 7.5% per annum rate of investment return; (2) general salary increases of 3.75% per annum; (3) 3.0% rate of Consumer Price Index increase; and (4) 0.95% annual growth in membership. The assumed long-term investment return used as the discount rate for determining the liabilities for each plan is 7.5% for the calculation of contribution rates for the 2017-19 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 10-year annualized investment returns on the retirement funds as of June 30, 2018, was 6.60%. The current contribution rates of employees and employers for PERS are 12.83% for employers and for employees 6.00% for PERS Plan 1, 7.41% for PERS Plan 2 and vary between 5.0% to 15.0% for PERS Plan 3.

All State Department of Retirement Systems ("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. Energy Northwest's total required contributions to PERS in Energy Northwest Fiscal Year 2018 were $17,871,000 ($7,213,000 related to PERS Plan 1 and $10,658,000 related to PERS Plan 2/3). Required contributions in Energy Northwest Fiscal Year 2017 were $15,680,000 ($6,780,000 related to PERS Plan 1 and $8,900,000 related to PERS Plan 2/3). Most of the required contributions to the PERS plans described above were paid by Columbia. Energy Northwest has a relatively small liability related to other post employment benefits ("OPEB"). The OPEB is related to grandfathered life insurance for retirees and deemed not material in nature and, therefore, not reported as part of the overall benefits in the notes to the financial statements

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, 2017, showed a 57% funded ratio (unfunded liability of $5,299,000,000) and an 89% funded ratio (unfunded liability of $3,975,000,000), 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, 2016, showed a 56% and 87% 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, 2018, included as Appendix C herein, for Energy Northwest's share of net liability and expenses.

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 is scheduled to terminate on January 1, 2052.

Columbia commenced commercial operation in 1984 and has a current net design electric rating of 1,174 megawatts. 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 $664.7 million for the 2019 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 $48.67 per megawatt-hour for the Energy Northwest Fiscal Year 2019. This cost is higher than the $36.54 per megawatt-hour for the Energy Northwest Fiscal Year 2018 because the Energy Northwest Fiscal Year 2019 includes a planned refueling and maintenance outage. The next refueling outage (R-24) is expected to begin on May 11, 2019 and is scheduled to last 35 days concluding on June 15, 2019. Energy Northwest continues to place a high priority on cost-containment.

Columbia was offline for six days in May 2018 when one of the station's main power transformers automatically disconnected from the transmission system following a grid disturbance. The transformer's protection system sensed an issue and initiated a trip signal, which resulted in a main generator trip that took Columbia offline. During this outage, Energy Northwest used the time to complete work on other plant equipment that can only occur when the plant is offline.

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.

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."

Recent Developments

Columbia produced more clean, nuclear energy for the Northwest power grid during 2018 than any other year in its 34-year history (more than 9.7 million MWh), surpassing the previous generation record set in 2016 of 9.6 million MWh. Columbia has set new generation records five out of the last seven years. Energy Northwest estimates Columbia's cost of power will average less than 4.2 cents per kilowatt-hour during its 2018-2019 fuel cycle, down from 6.3 cents, adjusted for inflation, during its 2010-2011 cycle.

In February 2017, McCullough Research published a 48-page study that stated that closing Columbia and replacing it with wind and solar resources would save Northwest electricity customers between $261.2 million and $530.7 million through June 2026. Physicians for Social Responsibility, an anti-nuclear energy activist group, circulated the report to the news media. A subsequent analysis released in May 2017 by the Public Power Council, based in Portland, Oregon, contradicted the study and concluded Columbia actually saves electricity customers $271 million a year compared to replacement costs by a utility scale solar resource. McCullough Research released an update of the study in January 2018. The update garnered no media attention or concern from Columbia stakeholders, including regional power organizations. In January 2018, Larry Makovich of IHS Markit presented a report to the Energy Northwest Executive Board noting that "[t]he 2017 McCullough Research report relies on flawed and misleading cost assessments to reach the erroneous conclusion."

A survey conducted during October and November 2017 by Bisconti Research found 87% of residents near Columbia have a favorable impression of the plant and the way it is operated, which is slightly higher than the national benchmark. One key survey finding shows support for Columbia comes from safe plant operations and favorable views of owner Energy Northwest regarding safety, the economy, jobs, the environment, and community outreach. The survey also shows local residents show a deep favorability to nuclear energy in general. A full 94% favor its use in the United States. Ninety-two percent of Columbia neighbors believe nuclear energy will be important to meeting the nation's electricity needs in the future. In addition, 86% of those surveyed said they would favor another nuclear energy facility located near Columbia.

The anti-nuclear energy activist group Physicians for Social Responsibility released a report in late October 2017 claiming the public could save as much as $1.18 billion in radioactive waste management and disposal expenses if Columbia would close by 2019. Energy Northwest found the report, prepared by Robert Alvarez at the Institute for Policy Studies in Washington, D.C., to contain a number of significant errors.

In January 2018, the Nuclear Energy Institute issued an analysis that found Columbia Generating Station contributes more than $690 million a year in positive community economic impact, including $475 million in Washington State alone. In addition, the study found the total number of jobs supported by Columbia annually is more than 3,930. The figures include direct and additional jobs created in the State and nationwide as a result of the expenditures from Columbia operations. The total economic benefit of Columbia operating through its end of license, currently 2043, is more than $8.9 billion for the State according to the study.

On March 7, 2019, while offloading new nuclear fuel from a delivery truck, one of the shipping containers slid off of a forklift and fell approximately 18 inches to the ground. There were no injuries and Energy Northwest's radiation protection department verified radiological conditions of the shipping container were unchanged. New fuel deliveries were temporarily suspended while the issue was investigated and appropriate corrective actions put in place. The dropped container, containing two fuel assemblies, was returned to the fuel vendor for inspection of the fuel and, as a conservative action, two new replacement fuel assemblies were shipped to the plant. As of March 27, 2019, all fuel required for the upcoming refueling outage has been received on site and moved into position for refueling. The NRC is aware of the issue, and Energy Northwest does not expect any regulatory action.

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 76.0% and has generated 251,219,028 MWh (net of station use) of electric power through January 2019. In the 10 Energy Northwest Fiscal Years ending June 30, 2018, however, the cumulative capacity factor was 86.0%.

Successful implementation of employee performance enhancement initiatives at Columbia has contributed to significant positive results in plant performance. Prior to the record set in 2016, the best generating calendar year in Columbia's history was in 2014 producing approximately 9.5 million megawatt-hours of electric power. Columbia produced 9.4 million megawatt-hours of electricity in Energy Northwest Fiscal Year 2018, as compared to 8.2 million megawatt-hours in Energy Northwest Fiscal Year 2017. The Energy Northwest Fiscal Year 2018 generation increase of 14.6% was because Energy Northwest Fiscal Year 2017 was a refueling outage year.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for Energy Northwest Fiscal Years ended June 30, 2017 and 2018 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 2017	Energy Northwest Fiscal Year 2018
Operations, Maintenance and Overhead	$239,901	$192,466
Nuclear Fuel	46,412	73,928
Generation Taxes	4,563	5,527
Decommissioning	7,766	8,163
Depreciation and Amortization	79,989	85,787
Investment Income	(736)	(1,559)
Interest Expense and Discount Amortization	126,427	139,452
DOE Settlement	(7,200)	(11,139)
Other Expense/(Revenue)	(10,355)	(10,951)
Total Costs	$486,767	$481,674
Net Generation (GWhs)	8,640	9,565

(1) Dollar amounts derived from audited 2017 and 2018 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 2018, Energy Northwest spent approximately $109.0 million on capital improvements at Columbia. Energy Northwest expects to spend approximately $110.0 million in Energy Northwest Fiscal Year 2019. 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 Energy Northwest Fiscal Year 2030, most of which are expected to be financed with Columbia Electric Revenue Bonds.

Expected Capital Improvements
(As of March 31, 2019)
(Dollars in Thousands)

Energy Northwest Fiscal Year	Total Capital
2019	$110,047
2020	67,819
2021	109,605
2022	81,274
2023	80,999
2024	72,639
2025	113,062
2026	93,632
2027	101,318
2028	102,353
2029	128,389
2030	122,240

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 June 30, 2018. See "Net Billed Projects Litigation and Claims."

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. In 2016 and 2017, Energy Northwest had two scrams (unanticipated shutdowns) with complications, which resulted in a White performance indicator. Prior to the White performance indicator in the third quarter of 2017, Columbia performance indicators were Green and had been so for more than six years. The determination on whether the August 2017 scram was required to be considered "complicated" was re-evaluated with the NRC, and in May 2018 Energy Northwest's request for a plant-specific exemption from counting the August 2017 scram as "complicated," was approved and the performance indicator returned to Green retroactively to January 1, 2018.

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. Prior to the White finding in the first quarter of 2017, there were no greater than Green findings at Columbia in over four years.

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.

In November 2016, Energy Northwest shipped certain radioactive material in the incorrect container on public roadways that did not comply with Department of Transportation regulations. The shipment traveled approximately 13 miles between Energy Northwest and U.S. Ecology on the Hanford Reservation. The shipment was delivered, rejected by U.S. Ecology, and transported back to Energy Northwest within approximately six hours. At no time was the public in any immediate danger. A special inspection was performed in December 2016 for this event.

The NRC held an exit conference on March 17, 2017, for the radiological waste shipping special inspection. A Regulatory conference was held in May 2017, to further discuss the potential findings as well as any associated corrective actions. NRC issued a White finding for a radioactive waste shipment sent to U.S. Ecology described above, and eight other findings associated with radioactive waste shipping. Columbia was placed in the Regulatory Response Column in the first quarter of 2017, and had to remain there through at least the end of 2017 and pass a supplemental inspection, which was held from November 28, 2017 to December 1, 2017, onsite and completed on December 19, 2017. Subsequently, the White finding in radioactive waste shipping was satisfactorily resolved. Energy Northwest took the steps to achieve satisfactory resolution with the White performance indicator for the August 2017 scram and Columbia was restored to the Licensee Response Column of the reactor oversight process.

As of February 6, 2019, the NRC's Regulatory Oversight Process Summary lists 93 plants in the Licensee Response Column, including Columbia, four plants in the Regulatory Response Column, one plant in the Multiple/Repetitive Degraded Cornerstone Column, and no plants in 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 has ongoing actions to address the areas for improvement. The next WANO Corporate Evaluation is scheduled for November 2023. Additionally, WANO completed a peer review of Columbia's station performance in October 2018. Several strengths 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 plant evaluations of all United States plants, including Columbia, approximately every four years. Additionally, INPO plant evaluations serve as a WANO follow-up peer review. The most recent plant evaluation of Columbia occurred in November 2016, noting strong performance in many areas. The next INPO plant evaluation is targeted for 2020. 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. The NPDES permit was renewed effective November 1, 2014 and is effective until October 31, 2019. Columbia formally submitted the application to renew the NPDES permit on April 30, 2019. 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.

Energy Northwest has submitted an application for a radioactive air permit from the State of Washington through EFSEC and the State's Department of Health. Washington is one of the few states that has elected to regulate radioactive air emissions under the Federal Clean Air Act, and discussions have been on-going with the Department of Health concerning the contents of the permit application. The permit application was completed in coordination with the Department of Health, and Columbia is awaiting issuance of the permit from EFSEC.

Impacts to the U.S. Nuclear Industry and the Columbia Generating Station from the Earthquake and Tsunami at the Fukushima Daiichi Plants in Japan

Since the earthquake and tsunami of March 11, 2011, that impacted the Fukushima Daiichi Plant in Japan, the U.S. nuclear industry has been working to first understand the events that damaged the reactors and then look to any changes that might be necessary at U.S. nuclear plants. Of particular interest is the performance of the General Electric ("GE") Boiling Water Reactor 3 with Mark I containment system.

Columbia is a newer design, GE Boiling Water Reactor 5, with a Mark II containment system. The Mark II containment system is a more robust containment design than the Mark I containment system.

Columbia is designed with multiple reactor cooling options to provide makeup water to the reactor and is designed with backup power for these systems in the event offsite power is lost. Backup power sources include three emergency diesel generators. All of this equipment is rigorously maintained and tested to strict performance standards to ensure it remains reliable for response during design basis external events.

Following the Fukushima accident, the NRC determined that all of the U.S. fleet of reactors is considered safe for continued operation. The NRC formed a task force to perform a systematic and methodical review to determine near-term and long-term changes that should be made to further ensure protection of public health and safety. As a result, Energy Northwest made and is making various capital improvements to Columbia.

In March 2012, the NRC approved three post-Fukushima orders. These orders encompass several requirements including: (1) implementing guidance and strategies to maintain reactor and containment cooling capabilities following an extreme event beyond a plant's design basis; (2) plants with Mark I and Mark II containments must install a reliable hardened vent for containment cooling and pressure control following extreme events that result in the loss of all off-site and on-site electrical power; and (3) all plants must install additional water level instrumentation in used fuel storage pools.

To date, Columbia has implemented the guidance and strategies necessary to maintain reactor and containment cooling capabilities. The hardened vent was installed and became operational in May 2017, and the additional water level instrumentation in the used fuel storage pool was installed in 2015.

In addition to the above orders, the NRC also required the following:

(1) All plants must perform and provide the results of a re-evaluation of the seismic and flooding hazards at their sites.

(2) All plants must perform seismic and flooding walkdowns.

(3) All plants must assess the ability of their current communications systems to perform under conditions of prolonged loss of off-site and on-site electrical power.

(4) All plants must assess the plant staffing level needed to respond to a large-scale natural event to implement strategies contained in the emergency plan.

Energy Northwest is in the process of responding to the above requirements. The flooding hazard re-evaluation has been completed and accepted by the NRC. The flooding hazard re-evaluation has no significant adverse impact on Columbia. Seismic re-evaluations are in progress and will be completed within the NRC agreed upon timetable, currently set for no later than September 2019. Seismic analysis to date indicates no significant adverse impact on Columbia. The seismic walkdowns, communications systems reviews, and plant staffing assessment have all been completed. Energy Northwest's total capital costs associated with the post-Fukushima NRC guidance are expected to be approximately $76.5 million, most of which has been spent.

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. Deliveries are expected to continue under this Program through 2022, and Energy Northwest has received all payments due in accordance with the TVA agreement as of the date of this Official Statement. The Enriched Uranium is stored at the Louisiana Energy Services enrichment plant in New Mexico for delivery to TVA.

Various parties have raised questions regarding the economics of the Program and the appropriateness of the roles of certain parties to the Program. Energy Northwest maintains the position that this Program continues to be in the best interest of the region's ratepayers.

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 for the 2019 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.

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.

On March 14, 2017, the State of Texas filed a lawsuit in the U.S. Court of Appeals for the 5th Circuit based on the DOE's failure to comply with the terms of the Standard Contract for Disposal of Spent Nuclear Fuel (the "Standard Contract"). The Standard Contract was executed by all U.S. nuclear generating utilities, including Energy Northwest, as required under the Nuclear Waste Policy Act of 1982 ("NWPA"), 42 U.S.C. § 10101 et seq. Among other things, the NWPA established a Nuclear Waste Fund to pay for the eventual permanent disposal of all U.S. commercially-generated spent nuclear fuel. Ratepayers for nuclear-generated electricity pay for the contributions to the Nuclear Waste Fund. In addition to other requests for relief in the lawsuit, Texas requested that all money paid to the government into the Nuclear Waste Fund be returned to the entities that paid into the fund.

Texas' request that the Nuclear Waste Fund be disgorged was strongly opposed by the Nuclear Energy Institute, which filed a brief opposing that portion of the petition. If granted by the U.S. Court of Appeals for the 5th Circuit, returning all money in the Nuclear Waste Fund would result in a determination that DOE was in total breach of the Standard Contract. Consequently, the Standard Contract would be null and void. Such a result would be significant to all nuclear generating utilities, including Energy Northwest, because the NWPA stipulates that no reactor can be licensed by the NRC if a Standard Contract is not in effect for disposal of the spent fuel generated by that reactor.

All expected filings have been made in this case. The next expected development is a decision by the U.S. Court of Appeals.

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 2018, was completed in May 2018 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 2022-2023 and will be commissioned in 2025. The two additional pads will have capacities of 36 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

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. Energy Northwest's current decommissioning plan is based on the Safstor method of decommissioning. 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 NRC requires that this deferred decontamination period be no longer than 60 years. DECON entails the facility and site containing radioactive contaminants are removed or lowered to levels that permit unregulated use shortly after cessation of operations.

Energy Northwest's current NRC minimum assurance estimate of Columbia decommissioning costs is approximately $507.84 million (in 2018 dollars). This estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia. Additionally, site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council. Energy Northwest's estimate of Columbia's site restoration costs is approximately $117.3 million (in 2018 dollars). Energy Northwest also has an estimate of $7.4 million (in 2018 dollars) for ISFSI (fuel storage) related costs.

The current decommissioning funding plan requires annual deposits to a fund through Energy Northwest Fiscal Year 2044, the end of Columbia's current operating license with the NRC. The plan assumes that such deposits will grow at a 2% real rate of return and that Columbia will be placed in an approximately 53-year DECON until 2097, at which time decontamination and dismantling will be completed. Over the life of the fund, deposits and the earnings related to the reinvestment thereof are expected to provide sufficient funds to cover the cash flow requirements to decommission Columbia. This plan will be re-examined every two years and modified, if necessary, to assure that the projected fund balance complies with the then current estimates and NRC requirements. Payments to the decommissioning trust fund have been made since 1985, and the balance of cash and investment securities in the fund as of March 31, 2019, totaled $298,247,840. A separate fund has been established for site restoration. The balance of this fund as of March 31, 2019, totaled $47,493,911. These amounts are held in external accounts administered by Bonneville.

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 are held by Energy Northwest. These payments are currently 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 is estimated at $7.4 million (in 2018 dollars). Energy Northwest is in discussion with Bonneville on transferring, in trust, the current funding amount and any future funding requirements from Energy Northwest to Bonneville. Such transfer is expected to occur in Energy Northwest Fiscal Year 2020. The fair market value of the cash and investments in this fund were $2,158,041 as of March 31, 2019.

GASB implemented a new 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 is implementing GASB Statement No. 83, effective with the Energy Northwest Fiscal Year 2019 annual reporting. Energy Northwest has completed an ARO cost estimate study of Columbia and ISFSI and is currently reviewing the results of the completed study and overall impacts to the Energy Northwest Fiscal Year 2019 reporting period. The major change required by Statement No. 83 is recognizing the current dollar value of the ARO as a liability on the balance sheet. A preliminary estimate of the ARO liability (in 2018 dollars) is $1.427 billion ($1.42 billion – Columbia and $7.37 million – ISFSI). The estimate utilizes the DECON scenario, which is an accepted NRC method. The estimate represents the current value of the ARO with a corresponding offset to deferred outflows. Energy Northwest has estimated the accounting adjustments and entries required by the implementation of Statement No. 83 will result in period decommissioning liability of $23.7 million to be recorded each year as a portion of the deferred outflow amount is decreased each year and the corresponding expense is recognized. The ARO liability does not determine the level of funding for the decommissioning funds discussed in the third and fourth paragraphs of this section. The accounting rules applicable to Bonneville differ from those applicable to Energy Northwest. See Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Columbia Generating Station Decommissioning and Restoration Cost."

PACKWOOD LAKE HYDROELECTRIC PROJECT

Energy Northwest owns and operates Packwood, a hydroelectric generating facility which is capable of generating 26 megawatts 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. The initial FERC license had a duration of 50 years and expired on February 28, 2010. Based on the existing FERC licensing process, Energy Northwest initiated relicensing efforts in Energy Northwest Fiscal Year 2005 and submitted an application requesting a new 50-year license to FERC in April 2008. On March 4, 2010, FERC issued a one-year extension to operate under the original license, which is indefinitely extended annually for continued operations, until a formal decision is issued by FERC and a new operating license is granted. On October 11, 2018, FERC approved a 40-year operating license for Packwood, effective October 1, 2018.

In Energy Northwest Fiscal Year 2018, production at Packwood totaled 99.609 net MWhs, up 1.4% from the previous year primarily due to more favorable snow conditions and runoff in Energy Northwest Fiscal Year 2018. Packwood's average availability during the last 15 years has been 98.45%, and has produced 5,143,902 net MWh since commercial operation began. The Packwood participants are required to pay their share of the annual budget of the project, whether or not 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 megawatts 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 megawatts each and there are an additional 14 wind turbines with 2.3 megawatts 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 5.92 cents per kilowatt hour during Energy Northwest Fiscal Year 2018. In Energy Northwest Fiscal Year 2018, Nine Canyon produced 250,374 net megawatt-hours of electricity, compared to 225,951 net megawatt-hours in Energy Northwest Fiscal Year 2017.

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 for Energy Northwest Fiscal Year 2019, is estimated at $10.2 million in 2018 dollars. Bonneville has placed funds in an external interest-bearing account in order to have sufficient funds for the eventual final remediation.

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. 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.

In 2013, Energy Northwest joined a teaming arrangement 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 project in the western U.S. Energy Northwest holds first right of offer to operate the project. By doing so, Energy Northwest expects to become one of the first industry experts for small modular reactors.

In October 2018, Energy Services and Development signed a participant agreement with the City of Richland to develop the Horn Rapids Solar, Storage, and Training Facility, a four megawatt photovoltaic solar power plant just north of Richland, Washington. Assuming development continues, the plant is expected to be operational in 2020.

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 will receive $405,000 in grant funds for this project based on $1,100,000 in eligible costs toward the purchase and installation of nine electric vehicle-charging stations located on previously underserved highway corridors in the State.

In March 2018, Energy Northwest entered a formal understanding with Terrestrial Energy USA to provide advice and siting assessment for an advanced nuclear reactor. In addition, Energy Northwest will advise the Canada-based developer on certain design aspects of its integral molten salt reactor. Similar to the 2013 agreement with Utah Associated Municipal Power Systems to potentially operate the first NuScale small modular reactor at the Idaho National Laboratory, the understanding with Terrestrial Energy provides Energy Northwest the right of first offer to operate the molten salt reactor.

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 $14.06 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 99 operating reactors to create the secondary layer of protection at $13.6 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.

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).

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.

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 cyber security program inspection by the NRC was in April 2013, and the next inspection is expected to occur in the second quarter of 2020. After the 2020 inspection, Columbia is expected to be on a three-year inspection cycle.

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:

<u>Energy Northwest v. United States of America (DOE or "government")</u>. On March 2, 2017, 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, 2019. The claim submission deadline is January 31 of the calendar year following Energy Northwest's fiscal year end. On January 30, 2019, Energy Northwest submitted its Energy Northwest Fiscal Year 2018 claim to DOE requesting reimbursement for $19,176,658. After submission, DOE has a set time to review and request additional information from Energy Northwest before making a determination on how much of Energy Northwest's claim it will pay. 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.

The total reimbursement to date from the government to Energy Northwest for partial breach of the Standard Contract was over $110,000,000, of which over $38,000,000 was reimbursed through the claims process for Energy Northwest Fiscal Years 2013 through 2017.

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

LEGAL MATTERS

The approving opinion of Foster Pepper PLLC, Bond Counsel to Energy Northwest, as to the legality of the Series 2019-A/B Bonds will be in substantially the form included in Appendix D-1—"PROPOSED FORM OF OPINION OF BOND COUNSEL FOR THE SERIES 2019-A/B BONDS." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the status of the interest on the Series 2019-A/B 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 2019-A/B 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 OPINION OF BOND COUNSEL FOR THE SERIES 2019-A/B 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

SERIES 2019-A BONDS

At closing of the Series 2019-A Bonds, Special Tax Counsel is expected to deliver its opinion, 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, that interest on the Series 2019-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 also is expected to deliver its opinion that interest on the Series 2019-A Bonds is not a specific preference item for purposes of the federal alternative minimum tax. In rendering its opinion, Special Tax Counsel will rely on the opinion of Bond Counsel as to the validity of the Series 2019-A Bonds and the due authorization and issuance of the Series 2019-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 2019-A/B BONDS."

To the extent the issue price of any maturity of the Series 2019-A Bonds is less than the amount to be paid at maturity of such Series 2019-A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2019-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 2019-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 2019-A Bonds is the first price at which a substantial amount of such maturity of the Series 2019-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 2019-A Bonds accrues daily over the term to maturity of such Series 2019-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 2019-A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2019-A Bonds. Beneficial Owners of the Series 2019-A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2019-A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2019-A Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2019-A Bonds is sold to the public.

Series 2019-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 2019-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 2019-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 2019-A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2019-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 2019-A Bonds may adversely affect the value of, or the tax status of interest on, the Series 2019-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 expected to deliver its opinion that interest on the Series 2019-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 2019-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 is expected to express 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 2019-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 2019-A Bonds. Prospective purchasers of the Series 2019-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 is expected to express no opinion.

The opinion of Special Tax Counsel is expected to be based on current legal authority, cover certain matters not directly addressed by such authorities, and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2019-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 is not expected to give 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 will covenant, however, to comply with applicable requirements of the 1986 Act, the 1986 Code and the 1954 Code.

Special Tax Counsel's engagement with respect to the Series 2019-A Bonds will end with the issuance of the Series 2019-A Bonds, and, unless separately engaged, Special Tax Counsel will not be obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2019-A Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than Energy Northwest, Bonneville and their appointed counsel, including the 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 2019-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 2019-A Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

SERIES 2019-B (TAXABLE) BONDS

At closing of the Series 2019-B (Taxable) Bonds, Special Tax Counsel is expected to deliver its opinion, based upon an analysis of existing laws, regulations, rulings and court decisions, that interest on the Series 2019-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code, or Section 103 of the 1986 Code. Special Tax Counsel is expected to express no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the Series 2019-B (Taxable) Bonds. In rendering its opinion, Special Tax Counsel will rely on the opinion of Bond Counsel as to the validity of the Series 2019-B (Taxable) Bonds and with the due authorization and issuance of the Series 2019-B (Taxable) 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 2019-A/B BONDS."

If Energy Northwest defeases any Series 2019-B (Taxable) Bond, such Series 2019-B (Taxable) Bond may be deemed to be retired for federal income tax purposes as a result of the defeasance. In that event, the Beneficial Owner of the Series 2019-B (Taxable) Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the Beneficial Owner's adjusted tax basis in the Series 2019-B (Taxable) Bond. See "DESCRIPTION OF THE SERIES 2019-A/B BONDS—DEFEASANCE."

GENERAL DISCLAIMER

Investors are urged to obtain independent tax advice regarding the Series 2019-A/B Bonds based upon their particular circumstances.

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2019-A/B Bonds.

RATINGS

Moody's Investors Service ("Moody's"), S&P Global Ratings ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2019-A/B Bonds the ratings of "Aa1" (negative 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 2019-A/B Bonds. In addition, Fitch has assigned Bonneville an "issuer default rating" of "AA-" (stable outlook). 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 2019-A/B Bonds.

UNDERWRITING

J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc. and Wells Fargo Bank, National Association (collectively, the "Underwriters") have jointly and severally agreed, subject to certain conditions, to purchase the Series 2019-A/B Bonds from Energy Northwest and to make a bona fide public offering of such Series 2019-A/B 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 2019-A Bonds is $1,188,953.89 and the aggregate Underwriters' compensation for the Series 2019-B (Taxable) Bonds is $71,667.99. 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 2019-A/B Bonds being sold under the contract of purchase if any of the Series 2019-A/B Bonds are purchased.

The Series 2019-A/B Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such Series 2019-A/B 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.

J.P. Morgan Securities LLC ("JPMS"), an underwriter of the Series 2019-A/B Bonds, has informed Energy Northwest that it has entered into negotiated dealer agreements (each, a "Dealer Agreement") with 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 2019-A/B Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any Series 2019-A/B Bonds that such firm sells.

The current business of Merrill Lynch, Pierce, Fenner & Smith Incorporated ("MLPF&S") is being reorganized into two affiliated broker-dealers (i.e., MLPF&S and BofA Securities, Inc.) in which BofA Securities, Inc. will be the new legal entity for the institutional services that are now provided by MLPF&S. This transfer is expected to occur on May 13, 2019 (the "Transfer Date"). MLPF&S, an underwriter of the Series 2019-A/B Bonds, will be assigning its rights and obligations as an underwriter to BofA Securities, Inc. in the event that the settlement date for the Series 2019-A/B Bonds occurs on or after the Transfer Date. For those Series 2019-A/B Bonds that settle after the Transfer Date, the Series 2019-A/B Bonds may be distributed by BofA Securities, Inc. to MLPF&S pursuant to a distribution agreement between BofA Securities, Inc. and MLPF&S. MLPF&S may in turn distribute the Series 2019-A/B Bonds to investors. As part of this arrangement, BofA Securities, Inc. may compensate MLPF&S as a dealer for its selling efforts with respect to the Series 2019-A/B Bonds.

Citigroup Global Markets Inc., an underwriter of the Series 2019-A/B Bonds, 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 through Fidelity at the original issue price. As part of this arrangement, Citigroup Global Markets Inc. will compensate Fidelity for its selling efforts.

Wells Fargo Bank, National Association, an underwriter of the Series 2019-A/B Bonds, has informed Energy Northwest that Wells Fargo Securities is the trade name for certain securities-related capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including Wells Fargo Bank, National Association, which conducts its municipal securities sales, trading and underwriting operations through the Wells Fargo Bank, NA Municipal Products Group, a separately identifiable department of Wells Fargo Bank, National Association, registered with the Securities and Exchange Commission as a municipal securities dealer pursuant to Section 15B(a) of the Securities Exchange Act of 1934. Wells Fargo Bank, National Association, acting through its Municipal Products Group ("WFBNA"), 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 2019-A/B Bonds. Pursuant to the WFA Distribution Agreement, WFBNA will share a portion of its underwriting compensation with respect to the Series 2019-A/B 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 2019-A/B 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.

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.

Merrill Lynch, Pierce, Fenner & Smith Incorporated is an affiliate of Bank of America, N.A. which has extended credit in other transactions to Energy Northwest and in other transactions supported by obligations of Bonneville under lease-purchase agreements.

JPMorgan Chase Bank, National Association has extended credit in other transactions to Energy Northwest and in other transactions supported by obligations of Bonneville under lease-purchase agreements.

Citigroup is an affiliate of Citigroup, N.A., which has extended credit in other transactions supported by obligations of Bonneville under lease-purchase agreements.

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

Wells Fargo Bank, National Association has extended credit in other transactions to Energy Northwest and in other transactions supported by obligations of Bonneville under lease-purchase agreements.

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 2019-A/B Bonds, for the benefit of the owners and beneficial owners of the Series 2019-A/B 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 2019-A/B 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, 2019. 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, 2019. 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 AGREEMENT."

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. It was discovered, however, that Energy Northwest filed some, but not all, bond rating changes resulting from insurance downgrades for certain bonds that are no longer outstanding. 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.

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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds, the agreements securing the Series 2019-A/B 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 2019-A/B Bonds is to be construed as a contract with the holders of such Series 2019-A/B 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 8, 2019, furnished by the Issuer (the "Official Statement") with respect to its Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A and Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable) (collectively, the "Series 2019-A/B 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 2019-A/B 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 2019-A/B 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.

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 2020 of approximately 10,214 annual average megawatts (defined below) under median water conditions and approximately 7,863 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 year and each annual average megawatt is equal to 8,760 megawatt-hours.)

Bonneville sells, purchases, and exchanges firm power, seasonal surplus energy (which is also referred to as “secondary” or “non-firm” 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 approximately three-fourths of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity 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 14 million people. Electric power sold by Bonneville accounts for approximately 27 percent of the electric power consumed within the Region.

Bonneville markets a large portion of this power to over 125 publicly-owned and cooperatively-owned 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 small number of companies (“Direct Service Industrial Customers” or “DSIs”) 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 early Fiscal Year 2019 that, on a planning basis in Operating Year 2020, it will meet 7,503 annual average megawatts of loads, of which approximately 87 percent is forecast to be Preference Customer loads, approximately two percent is forecast to be Reclamation loads for irrigation pumping stations, approximately two percent is forecast to be non-Reclamation federal agency loads, less than one percent is forecast to be DSI loads, and approximately eight 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, Bonneville has 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 $862 million in full and on time for Bonneville's fiscal year ended September 30, 2018 ("Fiscal Year 2018"). Bonneville also prepaid an additional $275 million principal amount of its Federal Appropriations Repayment Obligations (hereinafter defined). 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

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—Current Bonneville Power and Transmission Rates" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019." 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.

In anticipation of the expiration at the end of Fiscal Year 2028 of the Long-Term Preference Contracts and other agreements, Bonneville expects to begin engaging its customers through a public process in late 2019 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 expects to hold workshops in Fiscal Year 2021 to discuss proposals regarding key issues, release a policy and related record of decision in Fiscal Year 2023, and to execute new long-term power sales contracts and other agreements in Fiscal Year 2026.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Fiscal Year 2018 Financial Results

In Fiscal Year 2018, Bonneville made its scheduled United States Treasury payments on time and in full for the 35th consecutive year. Bonneville recorded net revenues in Fiscal Year 2018 of $471 million, an increase of approximately 39 percent from the prior fiscal year. For additional details related to Fiscal Year 2018 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2018." Bonneville finished Fiscal Year 2018 with Total Financial Reserves (as hereinafter defined) of $840 million, which is an increase of approximately 10 percent from the prior fiscal year. Total Financial Reserves is a financial metric that is not in accordance with accounting principles generally accepted in the United States of America ("GAAP") and is unaudited. Bonneville management believes that the use and reporting of Total Financial Reserves assists in reflecting the financial reserves Bonneville has on hand to meet current expenses. 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. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." Bonneville finished Fiscal Year 2018 with Reserves Available for Risk ("RAR") of approximately $551 million (Power Services' RAR of $13 million and Transmission Services' RAR of $538 million), a decline of approximately three percent from the prior year. The Fiscal Year 2017 year-end RAR amount included approximately $112 million related to expenses incurred in Fiscal Year 2017 that were not paid until Fiscal Year 2018 and revenues earned in Fiscal Year 2017 but not received until Fiscal Year 2018. Beginning in Fiscal Year 2018, similar short-term carryover cash flow effects at September 30 are no longer included in the calculation of fiscal year-end RAR. Due to these timing differences, Bonneville management believes that excluding the short-term carryover cash flow effects from RAR provides a more clear reflection of amounts available for risk mitigation. The primary reason for the decline in RAR at the end of Fiscal Year 2018 is the removal of the short-term carryover cash flow effects from the calculation of RAR at September 30, 2018. The short-term carryover cash flow effects are still included as part of Total Financial Reserves at September 30, but are now included in a financial metric

Bonneville refers to as Reserves Not Available for Risk ("RNAR") instead of RAR. 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. For a discussion of the non-GAAP financial metrics used by Bonneville, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics."

Fiscal Year 2019 Expectations and Related Information

On February 21, 2019, Bonneville announced that it is considering an adjustment in the amount of agency RAR allocated to Power Services and Transmission Services to more accurately represent the share of RAR derived from the respective business line's operations. As part of a thorough review of Total Financial Reserves and RAR calculations, Bonneville discovered an error in the cash model that allocates cash to Power Services and Transmission Services dating back to at least 2004. On March 11, 2019, Bonneville held a public workshop to discuss the error and proposed correction of the error by reallocating approximately $330 million of RAR from Transmission Services to Power Services. Bonneville is continuing to review its cash model that resulted in the error and, after accepting public comments regarding the final proposal, Bonneville will determine whether to reallocate RAR from Transmission Services to Power Services. Any reallocation of RAR would be applied prospectively starting in Fiscal Year 2019. Bonneville does not plan to restate any prior year-end business line RAR balances. The forecast 2019 fiscal year-end RAR for Power Services and Transmission Services discussed below assumes the effects of this proposed reallocation. Bonneville is conducting a comprehensive analysis to determine what led to the error and is implementing controls to regularly validate assumptions used in financial models to improve accuracy of its calculations going forward.

As of April 26, 2019, Bonneville forecast that it would finish Fiscal Year 2019 with RAR of $495 million (Power Services' RAR of $288 million and Transmission Services' RAR of $207 million), or approximately $56 million less than the approximately $551 million RAR as measured as of the end of Fiscal Year 2018. The primary reason for the forecast decline in RAR for the end of Fiscal Year 2019 is lower than forecasted net revenues due to decreased operating revenue, attributable to lower than expected loads, and higher than expected expenses, due primarily to increased power purchases. The change in forecast 2019 fiscal year-end RAR for Power Services and Transmission Services assumes the effects of the proposed reallocation of $330 million of RAR from Transmission Services to Power Services (as described above). The reallocation of $330 million of RAR from Transmission Services to Power Services has the effect of decreasing the likelihood of a Power CRAC (hereinafter defined) or Power Financial Reserves Policy Surcharge (as defined below). The likelihood of a Transmission CRAC or Transmission Financial Reserves Policy Surcharge remains zero. Such effects are included in the Fiscal Year 2020 CRAC and Financial Reserves Policy Surcharge probabilities described below.

As of April 26, 2019, Bonneville forecast that Fiscal Year 2019 net revenues will be $190 million, or approximately $281 million less than net revenues in Fiscal Year 2018; however, a substantial portion of forecast Fiscal Year 2019 net revenues is attributable to debt management actions related to Net Billed Bonds (as hereinafter defined) and other non-operating factors. See "—Regional Cooperation Debt and Related Actions." In Fiscal Years 2014-2018, such debt management actions and other non-operating factors have had similar effects on net revenues. See "—Fiscal Year 2018 Financial Results," "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results," and "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics."

Analyses as of April 29, 2019, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2019 water supply for the Columbia River basin will be approximately 91 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.

Based on Total Financial Reserve levels, forecasts of revenues and expenses and other internal updates as of the end of the second quarter of Fiscal Year 2019, Bonneville believes that it will meet its Fiscal Year 2019 United States Treasury payment responsibility on time and in full. Bonneville periodically reviews the probability that a CRAC or Financial Reserves Policy Surcharge will trigger and Bonneville's most recent review, released in April 2019, projected that there is a zero percent probability that a Power CRAC will trigger for application to certain Fiscal

Year 2020 power and related rate levels and a zero percent probability that a Transmission CRAC (hereinafter defined) will trigger for application to Fiscal Year 2020 transmission and related rate levels. Another rate level adjustment provision, the "Financial Reserves Policy Surcharge" (as discussed below), is available to increase power or transmission rates when financial reserves levels fall below an established threshold. Bonneville's most recent review, released in April 2019, projected that there is a 61 percent probability that a Power Financial Reserves Policy Surcharge will trigger for application to certain Fiscal Year 2020 power and related rate levels and a zero percent probability that a Transmission Financial Reserves Policy Surcharge will trigger for application to Fiscal Year 2020 transmission and related rate levels. There is a possibility that power rate levels will increase in Fiscal Year 2020 depending on a variety of factors. See "—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021."

Forecasts of fiscal year-end results, and whether the Power CRAC or Financial Reserves Policy Surcharge (as described below) would trigger to increase revenues in Fiscal Year 2020 and the amount of additional revenues, if any, the rate level adjustment mechanisms would be set to recover, 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.

Current Bonneville Power and Transmission Rates

To establish rates of general applicability for electric power and for transmission and related services, in July 2017, Bonneville filed final proposed power and transmission rates for Fiscal Years 2018 and 2019 (the "2018-2019 Rate Period") with FERC for its review. FERC granted final approval for such rates in March 2018. The rates approved by FERC are referred to herein as the "Final 2018-2019 Rates."

The Final 2018-2019 Rates reflect an increase in power rates and decrease in transmission rates over rates in the immediately preceding two-year rate period (the "2016-2017 Rate Period"). Average Tier 1 PF Rates increased by 5.4 percent, to $35.57 per megawatt hour; average Tier 2 PF Rates decreased by 3.9 percent, to $41.41 per megawatt hour; and average transmission rates decreased by 0.7 percent, in each case when compared to rates in effect in the prior rate period. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021

In support of the financial health objectives in Bonneville's Strategic and Financial Plans, Bonneville has issued (i) a policy to reduce Bonneville's total debt compared to assets (the "Leverage Policy") and (ii) a refinement to Bonneville's existing Financial Reserves Policy to establish possible rate actions when financial reserve levels fall below a certain threshold. The Leverage Policy and Financial Reserves Policy are implemented through Bonneville's rate development process. Just prior to each rate period, Bonneville will evaluate current leverage ratios and forecast leverage ratios for the next rate period using the best available information. The Administrator may choose to maintain or reduce the leverage of either of its business lines through various actions, including taking rate action. If the Administrator chooses rate action, Bonneville would propose in its rate case to include additional revenue financing or the payment of additional debt in an effort to make progress towards the leverage ratio targets.

Bonneville began conducting workshops in the spring of 2018 related to developing rates for electric power and for transmission and related services for Fiscal Years 2020 and 2021 (the "2020-2021 Rate Period"). Bonneville has issued the 2020-2021 Initial Rate Proposal, which began an administrative process that will culminate in a final rate proposal for the 2020-2021 Rate Period (the "2020-2021 Final Rate Proposal") and a record of decision. Bonneville expects to submit the 2020-2021 Final Rate Proposal and record of decision to FERC by the end of July 2019.

Consistent with longstanding policy, the 2020-2021 Initial Rate Proposal was, and the 2020-2021 Final Rate Proposal will be, 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 cost recovery adjustment clauses ("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 the payments under the Net Billing Agreements, the 1989 Agreement, and the Direct Pay Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Proposed Power Services Rate Increase

Based on the 2020-2021 Initial Rate Proposal, in December 2018, Bonneville estimated that average Tier 1 PF Rates would increase to approximately $36.78 per megawatt hour in the rate period, an increase of approximately 2.9 percent over the average Tier 1 PF Rates in effect in the current rate period. Bonneville also forecast that average Tier 2 PF Rates would be expected to decrease to approximately $27.26 per megawatt hour in the rate period, a decrease of approximately 34 percent over the average Tier 2 PF Rates in effect in the current rate period. For more details regarding the proposed average Tier 2 PF Rate decrease, 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."

The upward pressure on Power Services rates is primarily due to (i) efforts to meet protection and mitigation commitments for fish affected by the operation of the Federal System, (ii) possible implementation of a new Financial Reserves Policy Surcharge (as described below) to accelerate an increase in Power Services' financial reserves levels, (iii) forecast decreases in the firm power loads of Preference Customers to be met at Tier 1 PF Rates, in DSI loads to be met at the IP Rate, and, based on updated natural gas and energy market price forecasts, in the revenues forecast to be received from sales of seasonal surplus (secondary) energy and surplus firm power, and (iv) the 2020-2021 Rate Period being the first rate period where impacts of expensing energy efficiency program costs (due to the change that began in Fiscal Year 2016) are not offset by debt management actions. Bonneville is working to mitigate the effects of the upward pressure on Power Services rates by reducing program costs in order to minimize rate increases while continuing to take actions to improve its financial health. For more details regarding Bonneville's strategic plan, financial plan and other internal guidance, see "BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville's Financial Operations."

Proposed Transmission Services Rate Increase

Based on the 2020-2021 Initial Rate Proposal, in December 2018, Bonneville estimated that transmission and related rates would increase by approximately 3.6 percent over the average rates now in effect. The upward pressure on transmission rates arises primarily from increased debt service associated with past and anticipated capital spending for replacement of Federal System infrastructure and for new infrastructure associated with increased transmission usage and demands, increased system reliability and security requirements, and the integration of renewable resources.

Proposed Power Cost Recovery Adjustment Clause and Related Power Rate Level Adjustments

In the 2020-2021 Initial Rate Proposal, Bonneville has proposed to continue use of a rate level adjustment mechanism for power rates (the "Power Cost Recovery Adjustment Clause" or "Power CRAC"). The Power CRAC proposed in the 2020-2021 Initial Rate Proposal is similar to the Power CRAC for current power rates, as described in "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019." An increase in power and related rate levels under the proposed Power CRAC would occur if certain financial information resulted in Power Services' expenses that were higher and/or revenues that were lower than anticipated.

As proposed in the 2020-2021 Initial Rate Proposal, the Power CRAC would enable Bonneville to increase certain power and related rate levels over base rates to obtain up to $300 million in additional revenue in each of the two fiscal years of the rate period, without a time consuming rate proceeding, if Power Services' RAR are below zero at September 30. The Power Services' year-end RAR amount would be determined using the audited financial results of the Federal System that become available each October. Thus, if Power Services' RAR were below zero at September 30, 2019, then Bonneville would (subject to a *de minimis* exception described below) increase power and related rate levels in December 2019 through September 2020 to obtain additional revenues in Fiscal Year 2020. Likewise, if Power Services' RAR were below zero at September 30, 2020, then Bonneville would (subject to a *de minimis* exception described below) increase power and related rate levels in December 2020 through September 2021 to obtain additional revenues in Fiscal Year 2021. If a Power CRAC were to trigger for application to Fiscal Year 2020 power and related rate levels, Bonneville would notify customers by November 30, 2019.

The amount of additional revenue to be obtained under the Power CRAC in a fiscal year would be established, in general, to be the amount of the difference between zero and the Power Services' RAR at the beginning of the fiscal year in which Power CRAC is evaluated for implementation (this differential is referred to herein as the "Power CRAC Underrun"). More particularly, the Power CRAC would be used to obtain in a fiscal year: (i) all of the first $100 million of the Power CRAC Underrun, if any, for such fiscal year, and (ii) one half of any remaining Power CRAC Underrun for such fiscal year, up to a maximum of $200 million. The Power CRAC terms include a *de minimis* provision under which Bonneville would not trigger the Power CRAC for implementation for a fiscal year unless the Power CRAC Underrun (as described above) were to exceed $5 million. For more detail on the Power CRAC and other risk mitigation tools for power rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019."

In addition to the proposed Power CRAC mechanism, under the 2020-2021 Initial Rate Proposal, Bonneville also 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 several months.

Historically, Bonneville has included the use of certain provisions that would enable Bonneville to increase certain power and related rate levels on relatively short notice during the rate period, without a formal rate proceeding, in the event of certain possible developments related to fish and wildlife costs and operations. The National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment ("NFB Adjustment") and Emergency National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Surcharge ("Emergency NFB Surcharge") were rate adjustment features that would address unexpected costs or decreases in revenue ("NFB Financial Effects") in a fiscal year arising from the Endangered Species Act ("ESA") litigation relating to the Federal System ("NFB Trigger Event"). These mechanisms are still available for application during Fiscal Year 2019, if needed, but these mechanisms are not being proposed in the 2020-2021 Initial Rate Proposal. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "—Power Rates for Fiscal Years 2018-2019."

The Final 2018-2019 Rates included for the first time a "Spill Surcharge" to address financial effects arising from certain matters relating to ongoing litigation of the 2014 Columbia River System Supplemental Biological Opinion. See "—Developments Relating to the Endangered Species Act" and "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." The Spill Surcharge was designed to ensure that Bonneville was and is able to recover foregone revenue and costs to Power Services that result from potential increases in planned spill levels in Fiscal Years 2018 and 2019 (this information was unknown during rate case development). See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019." In establishing the 2020-2021 Initial Rate Proposal, certain assumptions were made regarding additional costs related to the court-ordered increased spill level (which is expected to be equivalent to impacts on Fiscal Year 2018 operations), which eliminates the need for a Spill Surcharge in the 2020-2021 Rate Period. See "—Developments Relating to the Endangered Species Act" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Bonneville's power rates have included a variety of rate level adjustment mechanisms. Most recently, the Spill Surcharge (as described above) was implemented for application to Fiscal Year 2018 rates. Prior to Fiscal Year 2018, the last Power CRAC and related power rate level mechanisms were implemented during the five-year rate period from Fiscal Year 2002 through Fiscal Year 2006 while recovering from the effects of the West Coast energy crisis in 1999-2001. See "BONNEVILLE LITIGATION—Litigation and Related Disputes Arising from the West Coast Energy Crisis in 1999-2001." Since Fiscal Year 2006, Bonneville's Power Services rates have been stable, especially when viewed from an inflation-adjusted perspective. See "POWER SERVICES—Historical PF Preference Rate Levels."

Proposed Transmission Cost Recovery Adjustment Clause

In the 2020-2021 Initial Rate Proposal, Bonneville has proposed to continue a rate level adjustment mechanism for transmission and related rates (the "Transmission Cost Recovery Adjustment Clause" or "Transmission CRAC"). An increase in transmission and related rate levels under the Transmission CRAC would occur if certain financial information resulted in Transmission Services' expenses that were higher and/or revenues that were lower than anticipated.

As proposed in the 2020-2021 Initial Rate Proposal, the Transmission CRAC 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 Transmission Services' RAR are below zero at September 30. The Transmission Services' year-end RAR amount would be determined using the audited financial results of the Federal System that become available each October. Thus, if Transmission Services' RAR were below zero at September 30, 2019, then Bonneville would increase transmission and related rate levels in December 2019 through September 2020 to obtain additional revenues in Fiscal Year 2020. Likewise, if Transmission Services' RAR were below zero at September 30, 2020, then Bonneville would increase transmission and related rate levels in December 2020 through September 2021 to obtain additional revenues in Fiscal Year 2021. If a Transmission CRAC were to trigger for application to Fiscal Year 2020 transmission and related rate levels, Bonneville would notify customers by November 30, 2019.

Proposed Financial Reserves Policy Surcharge

Coincident with the process for developing the Final 2018-2019 Rates, Bonneville adopted a Financial Reserves Policy that seeks to maintain and strengthen Bonneville's financial health. The Financial Reserves Policy provides for possible rate mechanisms that would increase and maintain RAR over time. The Financial Reserves Policy was implemented beginning with the 2018-2019 Rate Period. The refinements to the Financial Reserves Policy that were implemented in September 2018 are being applied as part of the 2020-2021 Initial Rate Proposal and will be applied in future rate periods.

The 2020-2021 Initial Rate Proposal includes for the first time a surcharge (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 its 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 $300 million. For Transmission Services, the amount of forecast cash expected to be needed to meet its operating expenses for 60 days is $94 million. As proposed in the 2020-2021 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 $30 million of additional revenue in each of the two fiscal years of the rate period if Power Services' RAR were below $300 million at September 30, 2019 or September 30, 2020. In future rate periods (beginning in Fiscal Year 2022), 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 $300 million at September 30. In addition, the proposed 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 $94 million at September 30, 2019 or September 30, 2020. If a Financial Reserves Policy Surcharge were to trigger for application to Fiscal Year 2020 power or transmission rate levels, Bonneville would notify customers by November 30, 2019 and increase power or transmission rate levels to obtain additional revenues in December 2019 through September 2020.

Reserves Distribution Clause

As proposed in the 2020-2021 Initial Rate Proposal, the power and transmission rates continue the availability of a feature parallel to, but the reverse of, the Power CRAC or Transmission CRAC, referred to as the "Reserves Distribution Clause" or "RDC." Similar to the prior rate mechanism referred to as the "Dividend Distribution

Clause," a Reserves Distribution Clause could decrease certain power or transmission rates in either year of the rate period, also based on RAR level thresholds by business line at September 30. In order to trigger a distribution under the Reserves Distribution Clause, Power Services' RAR or Transmission's RAR must exceed its 120 days cash on hand target ($600 million for Power Services or $188 million for Transmission Services). In addition, from an agency perspective, the total agency RAR must be at least $591 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 Administrator has discretion whether to decrease rates or to retain the RAR for additional payment of debt or to fund capital expenditures.

Uncertainty Regarding Proposed Rates and Rate Levels

The terms of the 2020-2021 Final Rate Proposal, including but not limited to the terms of base power and transmission rates, and the terms of a Power CRAC, Transmission CRAC, or Power or Transmission Financial Reserves Policy Surcharge, if any, could differ from those included in the 2020-2021 Initial Rate Proposal. Bonneville's expectations of rate levels for the 2020-2021 Rate Period and the likelihood that a Power CRAC, Transmission CRAC, or Power or Transmission Financial Reserves Policy Surcharge, 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 2019 and the terms of the 2020-2021 Final Rate Proposal.

Regional Cooperation Debt and Related Actions

Bonneville manages its overall debt portfolio, which includes both debt that is issued by non-federal entities and secured by Bonneville's financial commitments ("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. See "BONNEVILLE FINANCIAL OPERATIONS."

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 refinancings are currently known as "Regional Cooperation Debt."

An important component of Regional Cooperation Debt has been and is the issuance of Net Billed Bonds to refund outstanding Net Billed Bonds before their maturities (when substantial principal repayments were and are due) in Fiscal Year 2014 through Fiscal Year 2020. These refinancing Net Billed Bonds (which includes the Series 2019-A/B Bonds) increased or are expected to increase the weighted average maturities of outstanding Net Billed Bonds to match more closely the useful lives of facilities at the related Net Billed Projects as expected at the time the facilities were originally financed.

Additional Prepayment of Federal Appropriations Repayment Obligations

The Regional Cooperation Debt refinancings also had and 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. The freed up funds enable Bonneville (i) to repay, earlier than would otherwise occur, 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"), (ii) to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury (together with "Federal Appropriations Repayment Obligations" referred to as "Federal Repayment Obligations"), and (iii) to achieve other debt management goals.

In Fiscal Year 2014 through Fiscal Year 2018, Energy Northwest issued approximately $1.9 billion of Net Billed Bonds under the Regional Cooperation Debt approach which, combined with other coordinated cash management actions described below, enabled Bonneville to prepay an additional $2.5 billion in the aggregate of comparatively high interest Federal Appropriations Repayment Obligations over the amounts that Bonneville was scheduled to repay in such fiscal years. The amounts prepaid bore interest at a rate higher than the rates of interest on the refinancing Net Billed Bonds issued by Energy Northwest in Fiscal Year 2014 through Fiscal Year 2018 and such prepayments will result in total debt service savings of approximately $2.2 billion.

Bonneville estimates that the aggregate potential principal amount of refinancing Net Billed Bonds to be issued by Energy Northwest under the Regional Cooperation Debt initiative in Fiscal Year 2019 and Fiscal Year 2020 (including issuance of the Series 2019-A/B Bonds) could exceed $478 million which when combined with certain other coordinated cash management actions described below, are expected to enable Bonneville to accumulate additional balances in the Bonneville Fund to prepay an additional $250 million in Federal Repayment Obligations over the amounts Bonneville is scheduled to repay in Fiscal Year 2019 and Fiscal Year 2020. The amounts planned to be prepaid bear interest at a rate higher than the rates of interest on the projected refinancing Net Billed Bonds to be issued by Energy Northwest in Fiscal Year 2019 and Fiscal Year 2020 and are expected to result in total debt service savings of up to $469 million. There is no assurance that these savings will actually be realized.

Regional Cooperation Debt Beyond Fiscal Year 2020

Bonneville's Strategic and Financial Plans, 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. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program—Bonneville's Capital Financing Strategy." To address this need, Energy Northwest and Bonneville worked together to restructure Regional Cooperation Debt beyond Fiscal Year 2020 in a way that provides flexibility to shape and stabilize capital related costs over time enabling Bonneville to pay down, in a reasonable amount of time, Federal Repayment Obligations to help restore or preserve Bonneville's available capacity of its United States Treasury Borrowing Authority.

In September 2018, the Energy Northwest Board adopted a motion supporting the extension of Regional Cooperation Debt through Fiscal Year 2030; the issuance of additional Net Billed Bonds will require approval of the Energy Northwest Board. Bonneville estimates that the aggregate potential principal amount of refinancing Net Billed Bonds that could be issued in Fiscal Year 2021 through Fiscal Year 2030 could approach $3.5 billion. These Regional Cooperation Debt refinancings would 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. The freed up funds would enable Bonneville (i) to prepay a portion of its Federal Repayment Obligations or (ii) to directly fund Bonneville capital investments.

Short-Term Regional Cooperation Debt and Cash Management Actions

Energy Northwest, with Bonneville's support, has undertaken additional debt management actions affecting Fiscal Years 2016-2020. Energy Northwest has entered into short-term borrowing arrangements (in February 2016, October 2016, December 2017, and January 2019) to manage cash flows between Bonneville and Energy Northwest which have enabled Bonneville to increase the prepayment of certain Federal Appropriations Repayment Obligations at the end of Fiscal Year 2016 through Fiscal Year 2018 and will enable Bonneville to increase the prepayment of certain Federal Repayment Obligations at the end of Fiscal Year 2019, over the amounts that would otherwise have occurred, by approximately $1.1 billion in the aggregate. The short-term borrowing arrangements are expected to enable Bonneville to save up to $46 million in interest expense in Fiscal Year 2017 through Fiscal Year 2020, primarily reflecting the difference between Energy Northwest's cost of funds for the amounts borrowed under the short-term borrowing arrangements and the avoided interest expense to Bonneville resulting from prepaying the higher cost Federal Repayment Obligations one year earlier than otherwise expected.

The Energy Northwest short-term borrowing arrangements now in effect have funded and will fund, through the remainder of Fiscal Year 2019, a portion of interest on Net Billed Bonds and operation and maintenance expense for the Columbia Generating Station. The amounts borrowed under these short-term borrowing arrangements will be repaid by Energy Northwest with amounts received from Bonneville under existing contract commitments. For additional details regarding these short-term borrowing arrangements, see the Official Statement under "INTRODUCTION."

For more details on Regional Cooperation Debt and related actions, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Net Billed Bonds.

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 ESA. The listing under the ESA of certain anadromous 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 1990's, 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. Each of the biological opinions from 1993 on has been the subject of litigation. 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."

A biological opinion evaluates the effects of a federal agency action on species and habitat protected under the ESA and, if necessary, recommends a "Reasonable and Prudent Alternative" (as defined in the ESA) to the proposed action, consisting of measures and actions that, if implemented, will ensure the federal action is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. See "POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On May 4, 2016, the Oregon Federal District Court issued an order to the effect that NOAA Fisheries' most recent biological opinion evaluating the operation of the Federal System Hydroelectric Projects of the Columbia and Snake Rivers (referred to herein as the "2014 Columbia River System Supplemental Biological Opinion") did not meet the requirements of the ESA. The Oregon Federal District Court remanded the 2014 Columbia River System Supplemental Biological Opinion to NOAA Fisheries and ordered it to complete a final biological opinion by March 26, 2021. In addition to its findings under the ESA, the Oregon Federal District Court found the Corps and Reclamation did not comply with the National Environmental Policy Act ("NEPA") when they adopted the 2014 Columbia River System Supplemental Biological Opinion. The Oregon Federal District Court has directed that a new environmental impact statement under NEPA be prepared by March 26, 2021 and that the federal agencies' respective records of decision be issued on or before September 24, 2021. The Oregon Federal District Court further ordered that the Corps and Reclamation continue to implement the 2014 Columbia River System Supplemental Biological Opinion until the new biological opinion is prepared and filed. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." The expected timeline for completing the new environmental impact statement and biological opinion was shortened by approximately one year by the *Presidential Memorandum on Promoting the Reliable Supply and Delivery of Water in the West*, issued on October 18, 2018.

On January 8, 2018, after plaintiffs filed requests for injunctive relief with the Oregon Federal District Court seeking increased spring spill at eight Snake and Columbia River Federal System dams, the Oregon Federal District Court issued a final order, later upheld on appeal to the Ninth Circuit Court, directing increased spill for the spring 2018 fish passage season (approximately April-June 2018) at all eight Snake River and Columbia River Federal System dams identified in the injunction motions. On December 14, 2018, the Action Agencies, defendant intervenor State of Washington, plaintiffs the State of Oregon and the Nez Perce Tribe entered into an agreement in which the agencies agreed to specified spring spill operations in 2019 and 2020 in exchange for a pause in litigation on the biological opinion. The agreement sets the cost of spring spill to Bonneville at no more than the cost of the 2018 operations (operating under the court-ordered spill levels), which was $38.6 million. The cost in 2019 is expected to be approximately the same as 2018 operations and the 2020 cost is still being modeled. Because the agreement changed the proposed action, NOAA Fisheries issued a new biological opinion incorporating the agreed to spring spill operations, effective April 1, 2019 until a new action is adopted through records of decision in the ongoing Columbia River System Operations NEPA.

In accordance with the Spill Surcharge process (as described above), Bonneville modeled the expected cost of 2018 spring operations at $38.6 million. Bonneville identified cost reductions in the amount of $15.5 million to offset some of the Spill Surcharge. The 2018 Spill Surcharge amount recovered through Power Services' rates was approximately $10 million. On April 18, 2019, Bonneville held a public workshop to discuss the preliminary Fiscal Year 2019 Spill Surcharge formula. Bonneville expects to identify internal cost savings sufficient to entirely offset the expected cost of additional 2019 spring spill operations ($34.9 million); therefore, Bonneville is proposing that there be no Spill Surcharge in Fiscal Year 2019. Bonneville will accept public comments through May 2, 2019 and expects to issue a final decision regarding a Fiscal Year 2019 Spill Surcharge on May 16, 2019. See "—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Regarding capital investment at Federal System dams on the lower Snake River, the Oregon Federal District Court's ruling also states, "The Court will not enjoin any spending that is necessary for the safe operation of any dam," however, the court may enjoin any other spending and the ruling further states, "the Court will require the Federal Defendants to disclose sufficient information to Plaintiffs regarding the planned projects at each dam during the NEPA remand period, at appropriate and regular intervals." See "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Bonneville could also incur additional costs associated with contract termination or delays if the court were to enjoin certain capital projects at the lower Snake River dams. Consistent with the Oregon Federal District Court's order, Bonneville, with the other federal defendants, has disclosed at regular intervals planned projects at each of the Federal System dams on the lower Snake River. As of April 30, 2019, plaintiffs have not sought to enjoin any investment in these projects.

Bonneville is unable to predict the long-term implications of the ESA and NEPA litigation described herein, including the types of proposals and measures that NOAA Fisheries will include in the final biological opinion. Bonneville is also unable to predict whether and the extent to which the final biological opinion, any future court orders related to the litigation on the 2014 Columbia River System Supplemental Biological Opinion, or any future litigation in connection with the on-going ESA or NEPA processes, 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 $2.8 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 74 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 2018.

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 a low water period on record (which occurred in 1936-1937) for the Columbia River basin referred to herein as "Low Water Flows" (and is frequently referred to by Bonneville as "Critical 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 2020 (August 1, 2019 through July 31, 2020), the total Federal System would be capable of producing approximately 7,863 annual average megawatts of firm energy under Low Water Flows/Critical Water and not accounting for transmission line losses. This generation includes approximately 6,366 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,203 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including hydropower and renewable generation projects), and approximately 294 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 2020."

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 2020 is estimated to be approximately 81 percent of Bonneville's total firm power supply under Low Water Flows/Critical Water. See the table entitled "Operating Federal System Projects for Operating Year 2020." 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/Critical 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 (secondary) energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2020, the Federal System is forecast to generate seasonal surplus (secondary) energy of 1,845 annual average megawatts, assuming average water conditions (median water flows). In years with high water conditions (high water flows) the amount of seasonal surplus (secondary) energy could be as much as 3,299 annual average megawatts. In years with Low Water Flows/Critical Water, the amount of seasonal surplus (secondary) energy generated by the Federal System could be quite small or not available at all.

Notwithstanding that the amount and timing of seasonal surplus (secondary) energy is subject to variability, Bonneville markets almost all seasonal surplus (secondary) 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 following 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 United States of America, Department of Interior, Fish and Wildlife Service ("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 11 in the following table "Operating Federal System Projects for Operating Year 2020." 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 294 annual average megawatts of firm energy in Operating Year 2020. See Footnote 13 in the following table "Operating Federal System Projects for Operating Year 2020."

Operating Federal System Projects for Operating Year 2020

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. Bonneville utilizes an 80-year record of river flows based on the period from 1929-2008 for planning purposes. During this period, Low Water Flows occurred in 1936-1937, median water conditions ("Median Water Flows") occurred in 1957-1958, and high water conditions ("High Water Flows") occurred in 1973-1974. Bonneville estimates the energy generating capability of Federal System Hydroelectric Projects in a given operating year by assuming that these historical water conditions occur in that 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 2020, the Federal System January 120-Hour peaking capacity ("Peak Megawatts" or "Peak MW") and energy capability using (i) Low Water Flows (referred to as "Firm Energy"), (ii) Median Water Flows (referred to as "Median Energy"), and (iii) High Water Flows (referred to as "Maximum 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.

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Operating Federal System Projects for Operating Year 2020[(1)]

Project	Initial Service Year	Number of Units	January Capacity (120-Hour Peak MW)[(2)]	Maximum 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	4,198	2,808	2,422	1,972
Hungry Horse	1952	4	330	127	94	74
Other Reclamation Projects[(6)]		19	36	170	150	120
1. Total Reclamation Projects		56	4,564	3,105	2,666	2,166
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,221	1,582	1,377	1,125
John Day	1968	16	2,268	1,418	1,017	694
The Dalles w/o Fishway[(7)]	1957	22	1,697	972	805	545
Bonneville	1938	18	980	610	552	380
McNary	1953	14	1,062	659	549	413
Lower Granite	1975	6	806	389	250	111
Lower Monumental	1969	6	878	396	300	145
Little Goose	1970	6	873	331	255	130
Ice Harbor	1961	6	508	306	227	111
Libby	1975	5	484	254	227	182
Dworshak	1974	3	384	278	216	140
Other Corps Projects[(8)]		20	173	287	264	224
2. Total Corps Projects		149	12,334	7,482	6,039	4,200
3. Idle Federal Capacity[(9)]			(7,094)	0	0	0
4. Total Reclamation and Corps Projects (line 1 + line 2 + line 3)		**205**	**9,804**	**10,587**	**8,705**	**6,366**
Non-Federally-Owned Projects						
Other Non-Federal Hydro Projects[(10)]		4	15	43	31	29
Columbia Generating Station[(11)]	1984	1	1,169	1,116	1,116	1,116
Other Non-Federal Projects[(12)]		7	0	58	58	58
5. Total Non-Federally-Owned Projects		**12**	**1,184**	**1,217**	**1,205**	**1,203**
Federal Contract Purchases						
6. Total Bonneville Contract Purchases[(13)]		**n/a**	**429**	**312**	**304**	**294**
Total Federal System Resources						
7. Total Federal System Resources (line 4 + line 5 + line 6)		**217**	**11,417**	**12,116**	**10,214**	**7,863**

Source: 2018 Pacific Northwest Loads and Resources Study, Bonneville, April 2019.

(1) Operating Year 2020 is August 1, 2019 through July 31, 2020. Any discrepancies in totals for figures portrayed in this table and the 2018 Pacific Northwest Loads and Resources Study are due to rounding.

(2) January Capacity is megawatts of capacity ("MW") and is measured by Bonneville as "January 120-Hour Peak MW Capacity," which is the maximum generation to be produced under Low Water Flows in 20 six-hour periods (six hours a day, five days a week, for four weeks) assuming a base case of high loads as experienced historically in the month of January. January is a benchmark month for the Federal System peaking capacity because of the potential for high peak loads during January due to cold winter weather. These January estimates are further reduced by Bonneville for estimated hydro maintenance and estimates of idle Federal System hydro capacity. See footnotes (3) and (9), below.

(3) Maximum energy capability is the estimated amount of hydroelectric energy to be produced using High Water Flows for energy in annual average megawatts ("aMW"). Bonneville's hydro-regulation study incorporates spill assumptions to include similar operations to those implemented under court-ordered injunctions in Fiscal Year 2018 relating to the biological opinion for the Snake River and Columbia River dams. If and to the extent the effects of new biological opinions, operation settlements, court orders or other measures to protect fish and wildlife are different than those assumed in the 2018 Pacific Northwest Loads and Resources Study, such changes will be reflected in future hydro-regulation studies. See "—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 Flows for energy, in aMW.

(5) Firm energy capability is the estimated amount of hydro energy to be produced using Low Water Flows/Critical Water 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) The Federal System Hydroelectric Projects have more machine capacity from the generating units than fuel (river flows) available to operate all units on a continuous basis. "Idle Federal Capacity" is used for capacity only and estimates the amount by which the machine capacity exceeds the estimated capacity that would be available given the fuel availability (river flows) in a typical January.

(10) 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.

(11) 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 2020 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."

(12) Other Non-Federal Projects include project output from the following projects: shares of Foote Creek, LLC's Foote Creek I (1999), and Foote Creek IV (2000) wind projects, a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project, Condon Wind Project, LLC's Condon wind project, NWW Wind Power's Klondike Phase I (2001) wind project, a share from NWW Wind Power's

Klondike Phase III (2007), the output from the White Bluffs solar project (2002), and a share of the City of Ashland's solar project.

(13) 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 (secondary) 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 by purchasing physical power 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 discretionary sales of energy 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, and (vii) 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 transacting counterparties are composed of several principal groups: Preference Customers, DSIs, Federal Agencies, Regional IOUs, and parties ("Market Counterparties") with which Bonneville has commercial power-related arrangements that are not derived or originally derived from Bonneville's statutory 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 and consumer-owned electric cooperatives 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 power at Bonneville's lowest cost rate, the PF Preference Rate, for most of their loads. Under Public Preference, Bonneville must meet a Preference Customer's request for available Federal System power in preference to 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 uncommitted surplus Bonneville power to Preference Customers before meeting a competing request at a higher price for such uncommitted 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 2020, Bonneville forecasts that it will meet approximately 6,595 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. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. Most of the aluminum industry in the Pacific Northwest has ceased to operate. Currently, Bonneville has long-term contracts to sell power at the IP Rate directly to two DSIs—Alcoa, Inc. ("Alcoa") and Port Townsend Paper—in an aggregate amount of less than 100 annual average megawatts. On August 30, 2018, Alcoa provided notice to Bonneville that it intends to terminate its DSI contract on August 31, 2019. Beginning in Fiscal Year 2020, Bonneville will have one remaining long-term contract to sell power at the IP Rate directly to Port Townsend Paper—in an aggregate amount of up to 15 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 2020, Bonneville forecasts that it will meet approximately 179 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 2020, Bonneville forecasts that it will meet approximately 123 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." This rate would in effect reflect the marginal cost to Bonneville of acquiring power to meet the loads plus certain other costs.

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 New Resources 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, (iv) the Regional IOUs would not be able to control directly the terms and costs of the new resources Bonneville would obtain to meet the loads, and (v) the New Resources 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 the purchase, sale and/or exchange of power, 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 2020, Bonneville forecasts that Other Contract Deliveries will be approximately 635 annual average megawatts.

Bonneville sells and exchanges 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 and exchanges are composed of firm power and seasonal surplus (secondary) energy that are surplus to Bonneville's Regional requirements. Exports 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 to meet Regional loads before offering such power to a customer outside the Region. However, in the opinion of Bonneville's General Counsel, Bonneville is not required to reduce the rate of proposed export sales to meet a Regional customer's request if the proposed export sale is at a higher, FERC-approved rate than the Regional customer is willing to pay.

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 terminate such sales, upon advance notice, if needed to meet Bonneville customers' power requirements in the Region. 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 purchases of seasonal surplus (secondary) energy from Bonneville and these transactions account for a large share of revenues from Bonneville's Regional exports. The amount of seasonal surplus (secondary) 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. Litigation among Bonneville and parties from the Pacific Southwest arose out of the 1999-2001 West Coast energy crisis. See "BONNEVILLE LITIGATION—Litigation and Related Disputes Arising from the West Coast Energy Crisis in 1999-2001."

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 hydro-, 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 (all of which are Preference Customers) in terms of their percentage contribution to Power Services' overall sales revenue in Fiscal Year 2018.

Bonneville Power Services' Ten Largest Customers By Sales[(1)]
(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2018)

Customer Name	Approximate % of Sales
Snohomish County PUD No. 1	9%
Pacific Northwest Generating Cooperative	7%
City of Seattle, City Light Dep't.	6%
Cowlitz County PUD No. 1	6%
Tacoma Power	5%
Clark Public Utilities	4%
Eugene Water & Electric Board	3%
Benton County PUD No. 1	2%
Flathead Electric Cooperative, Inc.	2%
Central Lincoln PUD	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 service from Transmission Services.

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 to sell to each eligible utility, which includes Preference Customers and Regional IOUs, sufficient power to meet that portion of the utility's Regional firm power loads that it requests Bonneville to meet. Bonneville refers to these loads as "net requirements." 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. If Bonneville has or expects to have inadequate power 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 the 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, Bonneville provides a "Block" product under which the customer receives 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. (Currently two Preference Customers purchase a Block-only product from Bonneville in the amount of approximately 515 annual average megawatts; however, beginning in Operating Year 2020, three Preference Customers are expected to purchase a Block-only product from Bonneville in the amount of approximately 578 annual average megawatts.)

Over 100 Preference Customers and all of Bonneville's nine federal agency customers purchase Load Following service and for Operating Year 2020 Bonneville forecasts that these loads will be approximately 3,447 annual average megawatts. By contrast, 14 separate Preference Customers purchase on a Slice/Block basis. For Operating Year 2020, Bonneville forecasts that its Slice/Block loads will be approximately 2,871 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. One Preference Customer, with Bonneville's consent, has elected under certain provisions of its Long-Term Preference Contract to change the type of power product it will purchase from Bonneville. Beginning in Fiscal Year 2020 (October 1,2019): (i) the aggregate amount of Slice that Bonneville will sell will decline to 22.4 percent of the Federal system (currently the amount is 22.7 percent) and (ii) Block sales will increase by approximately 40 annual average megawatts. The Long-Term Preference Contracts contain no further rights allowing Preference Customers to elect to change the type of service received thereunder.

For reference, the Slice portion of Slice/Block service currently represents approximately 22.7 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 market 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 bears 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 to be served at Tier 1 PF Rates has been estimated at 6,634 annual average megawatts for Fiscal Year 2020 and 6,667 annual average megawatts for Fiscal Year 2021.

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 for a potential sale to DOE, and (ii) up to 250 annual average megawatts in aggregate, if necessary, for new Preference Customers and load growth of certain Indian tribe 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 uses a "Tiered Rates Methodology" that defines the costs that are and will be allocated to Tier 1 PF Rates, including but 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 (secondary) energy from the Federal System are provided to Preference Customers in Tier 1 PF Rates. In the case of Slice, the related customers receive a proportionate share of Federal System seasonal surplus (secondary) 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 (secondary) 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 130 annual average megawatts of Tier 2 Loads in Fiscal Year 2019 and approximately 55 annual average megawatts in Fiscal Year 2020. Tier 2 Loads were 79 annual average megawatts in Fiscal Year 2017 and 112 annual average megawatts in Fiscal Year 2018. As required under the Long-Term Preference Contracts, those customers requesting that Bonneville meet their Tier 2 Loads through Fiscal Year 2024 have made their elections. However, the aggregate amount of Tier 2 Loads that Bonneville will be obligated to meet in Fiscal Years 2022 through 2024 will not be finally determined until each rate case within that period. Similar Tier 2 Load elections and advance notice to Bonneville are required in the four fiscal years beginning with Fiscal Year 2025.

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 and potential Tier 2 Load growth, Bonneville expected that it would be possible that Tier 2 PF Rates could be lower than Tier 1 PF Rates starting in Fiscal Year 2020. During the 2016-2017 Rate Period, average Tier 2 PF Rates were approximately $43.09 per megawatt hour and average Tier 1 PF Rates were approximately $33.75 per megawatt hour. During the current rate period, average Tier 2 PF Rates are approximately $41.41 per megawatt hour and average Tier 1 PF Rates are approximately $35.57 per megawatt hour. As proposed in the Fiscal Year 2020-2021 Initial Rate Proposal, average Tier 2 PF Rates are expected to be approximately $27.26 per megawatt hour and average Tier 1 PF Rates are expected to be approximately $36.78 per megawatt hour. The lower 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. In previous rate periods, Bonneville made longer advance purchases to serve its anticipated Tier 2 Loads, but Bonneville currently makes 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). Tier 2 Rates have declined due to the change in timing of advance purchases and lower market prices for electricity. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021."

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 2018 Loads and Resources Study, Bonneville projected that it would have an energy surplus of approximately 79 annual average megawatts in Operating Year 2020 and an energy deficit of approximately 123 annual average megawatts in Operating Year 2021, assuming Low Water Flows/Critical Water and transmission line losses. If this planning surplus materializes, Bonneville anticipates that it will sell the related power in west coast energy markets. Between Operating Years 2021 and 2029, Bonneville forecasts annual planning deficits that vary between 123 annual average megawatts (in Operating Year 2021) and 438 annual average megawatts (in Operating Year 2025). 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 (secondary) 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 loads, (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 loads, (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 meet load obligations, Bonneville may have to obtain electric power from sources 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 acquire "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 generation resources. The extent to which Bonneville does so will depend on the effects of electric power markets, power sales contract terms, load growth, and other factors.

The acquisition of resources under the standards and procedures of the Northwest Power Act, however, is not the sole method by which Bonneville may meet its power requirements. Other methods are available. These include, but are not limited to: (i) exchange of surplus Bonneville peaking capacity for firm energy; (ii) receipt of additional power from improvements at federally- and non-federally-owned generating facilities; and (iii) purchase 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 Seventh Northwest Conservation and Electric Power Plan (the "Seventh Power Plan") in early calendar year 2016. The Seventh 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. In February 2019, the Council published its mid-term assessment, assessing progress towards achievement of the regional goals. The Seventh 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 2021. The Seventh Power Plan's second priority is to develop the capability to deploy demand response resources or rely on increased market imports to meet future system capacity needs under critical water and weather conditions. After energy efficiency and demand response, the Seventh Power Plan identifies new natural gas-fired generation as the most cost-effective resource option for the Region in the near-term. The Seventh Power Plan does not foresee renewable resource development as necessary beyond the approximately 100 to 150 annual average megawatts of energy expected to be achieved through existing state renewable portfolio standards. In February 2019, the Council kicked off the development of its next power plan, which is expected to be finalized in 2021.

Bonneville's updated 2016-2021 Energy Efficiency Action Plan forecasts that Bonneville will achieve a range of 560-600 average megawatts of conservation in partnership with its Preference Customers and others through 2021. As of January 2019, Bonneville is on track to meet this conservation goal. 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, capacity in extreme weather events, and hourly balancing reserves which inform Bonneville's Resource Program.

Bonneville's most recent Resource Program, which was published in Fiscal Year 2018 (the "2018 Resource Program"), concluded that Bonneville can satisfy much of its expected supply obligations with electric power conservation and short-term power purchases from wholesale power markets.

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

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

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

Renewable Energy. Bonneville presently purchases a total of approximately 58 annual average megawatts from various wind energy projects in Wyoming, Oregon, and Washington and small amounts of power from a solar photovoltaic project. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project. This project has not been built. It was originally scheduled to become operational in December 2005, but it is not clear yet whether the site is a viable geothermal resource and the project site is the subject of on-going environmental litigation. Bonneville's expectation of the earliest date for commercial operation has been extended beyond October 1, 2021.

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. 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's 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 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. As part of the settlement, the schedule of aggregate program benefits for the Regional IOUs ranges from $259 million to $309 million per fiscal year, while the schedule of actual aggregate cash payments to the Regional IOUs range from $182 million to $286 million (the actual aggregate cash payments are calculated by subtracting Refund Amounts, as described below, from the schedule of aggregate program benefits for each fiscal year).

The settlement also provides remuneration to Preference Customers for past adverse power rate effects caused by the past overpayments of Residential Exchange benefits to the Regional IOUs. Bonneville recoups the value of the past overpayments from the Regional IOUs by deducting from their calculated Residential Exchange Program benefits approximately $77 million in aggregate per fiscal year. These offsetting reductions (in effect since Fiscal

Year 2012 and continuing through Fiscal Year 2019) are referred to by Bonneville as “Refund Amounts.” Under the settlement, actual aggregate cash payments to the Regional IOUs are set at approximately $232 million in aggregate for Fiscal Year 2019 (aggregate program benefits of approximately $309 million less deductions for annual Refund Amounts of approximately $77 million). Bonneville provides the value of the annual Refund Amounts directly to Preference Customers in the form of cash payments or credits on their power bills from Bonneville. As of the end of Fiscal Year 2018, the aggregate overpayment of Residential Exchange Program benefits that have not yet been recouped by Bonneville (and conveyed to Preference Customers) was approximately $77 million.

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 control).

Bonneville also funds measures recommended by the Council to implement the Council’s Fish and Wildlife Program. 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’ 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 2016 through 2018.

Fish and Wildlife Financial Impacts by Type
(Fiscal Years 2016-2018, dollars in millions)

	2018	2017	2016
Direct Costs	$ 454	$ 461	$ 495
Estimated Operational Impacts[(1)]:			
Replacement Power purchases	24	(21)	50
Foregone Power Revenues	3	10	77
Total Fish and Wildlife	**$ 481**	**$ 450**	**$ 622**

(1) Unaudited metric that is not in accordance with GAAP.

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 and Foregone Power Revenues are the result of changes in prices due to energy market conditions and differences in monthly hydro generation shape.

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 resulting 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 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 control 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 NOAA Fisheries' most recent biological opinion for the Columbia and Snake Rivers, the 2014 Columbia River System Supplemental Biological Opinion. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

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, are 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," below.

Description of the 2014 Columbia River System Supplemental Biological Opinion. As noted herein, litigation challenging the 2014 Columbia River System Supplemental Biological Opinion has resulted in a determination, by the Oregon Federal District Court, that it does not meet the requirements of the ESA. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act." The Oregon Federal District Court has directed that the Corps and Reclamation continue to implement the 2014 Columbia River System Supplemental Biological Opinion until a new biological opinion is issued.

Since the 2014 Columbia River System Supplemental Biological Opinion expired of its own terms and the agreed to spring spill operations, 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. NOAA Fisheries issued a new biological opinion effective April 1, 2019 to cover operations and maintenance of the Columbia River System until a new action is adopted through records of decision in the ongoing Columbia River System Operations NEPA. The 2019 NOAA Fisheries Columbia River System Biological Opinion found that the proposed action was not likely to jeopardize the continued existence of the ESA-listed species or destroy or adversely modify their designated critical habitat.

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.

Among the issues raised by the plaintiffs in the litigation challenging the 2014 Columbia River System Supplemental Biological Opinion was whether in adopting and implementing the biological opinion and related mitigation actions the Action Agencies should have completed a new environmental impact statement rather than relying on existing NEPA documents, including the Columbia River System Operation Review Environmental Impact Statement. In its opinion dated May 4, 2016 remanding the 2014 Columbia River System Supplemental Biological Opinion, the Oregon Federal District Court also ruled that the Corps and Reclamation violated NEPA. See CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation." In response to the court's observations and comments received during the public comment period, the Action Agencies are analyzing an alternative that includes the breaching of the four lower Snake River dams. However, it is the opinion of 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. Bonneville is unable to predict whether the current or future ESA litigation or the new biological opinion will change the prospects that such legislation will be proposed in Congress or enacted into law.

The court has ordered the federal government to complete the new environmental impact statement on or before March 26, 2021 and that the federal agencies issue their records of decision regarding the implementation of the ESA on or before September 24, 2021. The timeline for completing the new environmental impact statement was shortened by one year by the *Presidential Memorandum on Promoting the Reliable Supply and Delivery of Water in the West*, issued on October 18, 2018. The draft environmental impact statement is now due in February 2020 and the final environmental impact statement will be due in June 2020. The signing of the records of decision is set for September 2020, one year earlier than the previous court ordered schedule.

Impacts on Bonneville's Rates. Bonneville is required by federal law to establish rates that are sufficient to recover all of its costs. In developing the 2018-2019 Final Rate Proposal, Bonneville made assumptions of the possible range of expected incremental costs that could arise under the 2014 Columbia River System Supplemental Biological Opinion and the possible cost exposure to Bonneville of the 2014 Columbia River System Supplemental Biological Opinion. As the possible range of expected incremental costs that could arise under the new biological opinion ordered by the Oregon Federal District Court becomes clearer Bonneville similarly will make assumptions of cost estimates and other impacts of the new biological opinion for recovery in future rates.

In developing the 2018-2019 Final Rate Proposal, Bonneville made certain assumptions of the potential costs and other effects from compliance with the ESA to assure full cost recovery in Bonneville's rates. Bonneville's current 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 in response to increased costs arising from actions under the ESA. In addition, the 2018-2019 Final Rate Proposal included for the first time a Spill Surcharge to ensure recovery of costs from potential increases in planned spill levels. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "–Developments Relating to the Endangered Species Act" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019." In its 2020-2021 Initial Rate Proposal, Bonneville made certain assumptions of the potential costs and other effects from compliance with the ESA to assure full cost recovery in Bonneville's rates. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021.

The costs to Bonneville in preparing the new environmental impact statement that the Oregon Federal District Court has ordered the federal government to prepare will also be included for recovery in Bonneville's rates. Bonneville's preliminary estimate of the costs it will bear from the preparation of the new environmental impact statement, including Bonneville's own direct expense and amounts to be provided to the Corps and Reclamation through operations and maintenance direct funding, is approximately $44 million in aggregate in Fiscal Year 2017 through Fiscal Year 2020 (when the environmental impact statement is expected to be completed). Bonneville expects that the net increase in costs for the environmental impact statement efforts will be reduced substantially by the reprioritization of other work during the study period. In addition, a portion of the costs of the environmental impact statement is expected to be appropriated by Congress to the Corps (primarily related to the Columbia River Fish Mitigation program, as described below) and capitalized and repaid by Bonneville over a 75-year repayment period.

The Columbia River Fish Mitigation Program. As noted above, the Oregon Federal District Court has directed the Corps and Reclamation to continue to comply with the 2014 Columbia River System Supplemental Biological Opinion. The 2014 Columbia River System Supplemental 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 75 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 Federal Appropriations Repayment Obligations as they are completed and placed in service.

As of the end of Fiscal Year 2018, Bonneville was responsible for $1.2 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 $215 million through Fiscal Year 2023. This would bring the total amount of Bonneville's Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation to approximately $1.4 billion by the end of Fiscal Year 2023. The amounts ultimately appropriated under the Columbia River Fish Mitigation program (through Fiscal Year 2023 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 2023, 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 new 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. Bonneville, the Corps, and Reclamation, and a number of Regional interests including six tribes, an inter-tribal association, and the states of Washington, Montana and Idaho signed seven separate agreements to assure long-term mitigation funding to address Federal System Hydroelectric Projects' responsibilities for effects to fish and wildlife. The foregoing agreements, collectively known as the Columbia Basin Fish Accords, have helped the Action Agencies protect, mitigate, and enhance fish populations and fish habitat in the Columbia River basin and address the Action Agencies responsibilities for ESA-listed fish.

Under the original Columbia Basin Fish Accords, Bonneville committed to make available approximately $995 million through Fiscal Year 2018. As of the end of Fiscal Year 2018, the remaining unobligated commitment under all Columbia Basin Fish Accords, after taking into account later Accords and modifications, was approximately $97 million. (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 estimates that most of its funding commitments under the Columbia Basin Fish Accords have been and will be for work necessary to implement biological opinions affecting the Federal System Hydroelectric Projects and for work otherwise agreed to in furtherance of federal statutory fish and wildlife responsibilities such as those under the Northwest Power Act.

The Columbia Basin Fish Accords were intended to provide a high level of assured long-term funding for biological opinion implementation and other mitigation actions.

Under certain of the Columbia Basin Fish Accords, the participating tribes and states agree that the federal government's responsibilities under the ESA, the Federal Water Pollution Control Act, and the Northwest Power Act are satisfied as to the effects of the Hydroelectric Projects in the Snake River and Columbia River drainages.

The original Columbia Basin Fish Accords expired in 2018, except for the Kalispel Tribe's Accord, which began several years after the others and expires on September 30, 2022. To preserve the benefits of those agreements and to assure ongoing funding and implementation of mitigation, the Action Agencies executed extensions of the Columbia Basin Fish Accords with five tribes, an inter-tribal association, and the states of Montana and Idaho for an additional commitment of $449 million over four years to continue the existing portfolios of state and tribal mitigation projects. The average annual commitment during the extension period is less than the Fiscal Year 2018 funding levels for those same projects, so there will be no increase in annual costs over Fiscal Year 2018 spending levels as a result of the extensions. The extended Columbia Basin Fish Accords now expire the earlier of September 30, 2022, or upon the issuance of final decision documents by Bonneville, the Corps, and Reclamation in the Columbia River System Operation National Environmental Policy Act process. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE— Developments Relating to the Endangered Species Act." Bonneville's agreement with the State of Washington, which focused on Columbia River estuary habitat improvement, has not been extended although negotiations could continue.

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 Flood Control Project Biological Opinion. The Corps owns and operates 13 dams in the Willamette River Basin (the "Willamette Project") for the primary purpose of flood risk reduction, and also for power, recreation, and water supply purposes. The Willamette Project is included in the Federal System and Bonneville markets the power from the Willamette Project and funds the Corps for the power purpose share of both capital and operation and maintenance costs at the facilities of the Willamette Project. Bonneville estimates that approximately 180 megawatts of power are produced by the Willamette Project under average water conditions.

NOAA Fisheries issued its Willamette River Basin Flood Control Project Biological Opinion (the "Willamette BiOp") in 2008. The 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 Willamette BiOp was also adopted in a separate biological opinion by the Fish and Wildlife Service.

To fulfill the requirements of the 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), but those potential measures are currently undergoing environmental review under NEPA.

On March 13, 2018, three environmental protection organizations filed an action against the Corps and NOAA Fisheries in the Oregon Federal 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 which could result in changes to or replacement of action items that could further increase costs to Bonneville. On April 9, 2018, the Corps reinitiated ESA Section 7 consultation for operation and maintenance of the Willamette Project with NOAA Fisheries. Discussions among the Corps, NOAA Fisheries, and Bonneville are ongoing regarding the feasibility and implementation of particular measures under the existing Willamette BiOp/COP, the ongoing NEPA processes and the ESA Section 7 consultation process. On November 30, 2018, the plaintiffs filed a motion for preliminary injunction against the Corps and NOAA Fisheries, seeking a court order that would require the Corps to conduct certain operational measures for downstream fish passage and temperature control. Federal defendants and defendant-intervenors (City of Salem and Marion County) filed oppositions to the motion on February 25, 2019. On January 31, 2019, the City of Salem and Marion County also moved to assert NEPA and ESA cross-claims against the Corps and NOAA Fisheries related to proposed downstream passage measures at Detroit dam.

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 up to 75 years from the dates that related modifications are placed in service.

Bonneville conservatively estimates the power impacts of the five interim fish passage operations proposed in Plaintiffs' request for injunctive relief could result in lost revenues exceeding $4 million per year based on the average annual market value of power produced at each dam; however, more extensive modeling is needed to better understand the seasonal impacts of the proposed measures. Given the relatively small percentage of the Willamette Project's costs that are allocated for recovery in Bonneville's rates, and because these potential costs would be only a part of the many financial obligations that Bonneville recovers in its rates, Bonneville does not anticipate that possible future modifications to the Willamette Project would have a significant effect on Bonneville's overall power rate levels. However, 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 current 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. Bonneville can make no prediction of the total costs or consequences to it with respect to the Willamette Project arising under the ESA.

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 operation and maintenance costs with respect to the Willamette Project for Fiscal Year 2026 through Fiscal Year 2043. Bonneville will negotiate its funding obligations based on historical funding levels and contemporaneous needs and conditions.

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the 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 $73 million, $54 million, and $70 million in Fiscal Years 2016, 2017, and 2018, 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-2015") 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 is currently updating its fish and wildlife program and expects to complete this process in December 2019.

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 1990's, 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 2018, Integrated Program expense was $290 million, and Federal System capital investment was $31 million. Bonneville forecasts that Fiscal Year 2019 Integrated Program expense and Federal System capital investments will be $302 million and $44 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 2018-2019

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's 2018-2019 Final Rate Proposal for power and transmission rates of general applicability and FERC has granted final approval thereof. The final Tier 1 rates for the 2018-2019 Rate Period for power sold to Preference Customers for their requirements vary depending on the particular power product provided by Bonneville. Average PF Preference Rates (inclusive of the Slice, Block and Full Requirements products) increased by 5.4 percent over the prior average rates, to $35.57 per megawatt hour. Under the Final 2018-2019 Rates, average Tier 2 PF Rates are 3.9 percent lower than in the prior rate period, decreasing to $41.41 per megawatt hour. Tier 2 PF Rates apply to certain incremental loads that Preference Customers require Bonneville to meet. Bonneville currently sells about 132 annual average megawatts of power at Tier 2 PF Rates. For a discussion of 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 2018-2019 Rates have continued the use of certain features (in some cases slightly modified) from prior final power rates. For instance, the power rates have continued the use of (i) "base rates" for Regional power sales that are set at levels Bonneville believes to be sufficient to yield a reasonably high probability of sufficient net revenue, and (ii) a Power CRAC to increase certain power (and certain ancillary services) rate levels during the 2018-2019 Rate Period. It was designed to trigger if certain measures reflective of Power Services' financial performance decline to a Power CRAC Threshold level. While the Power CRAC did not (and will not) trigger in the 2018-2019 Rate Period, it was available if necessary to increase Power Services' revenues, primarily from the sale of Block and Load Following power products, by up to $300 million per fiscal year without a formal rate proceeding.

The Final 2018-2019 Rates included for the first time a "Spill Surcharge" to address financial effects arising from certain matters relating to ongoing litigation of the 2014 Columbia River System Supplemental Biological Opinion. In its ruling the court directed the federal government to "increase spill" during the spring at certain Federal System dams to assist salmonid species listed under the ESA. Spill has the effect of reducing the amount of water that runs through hydroelectric turbines for generation. On January 8, 2018, the Oregon Federal District Court issued a final order directing increased spring spill for the 2018 fish passage season. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act" and "—Fish and

Wildlife—The Endangered Species Act" and "BONNEVILLE LITIGATION—Columbia River ESA Litigation." The Spill Surcharge is designed to ensure that Bonneville is able to recover foregone revenue and costs to Power Services that result from potential increases in planned spill levels in Fiscal Years 2018 and 2019.

As provided in the Final 2018-2019 Rates, the Spill Surcharge would be implemented annually, if needed, in each of Fiscal Years 2018 and 2019 based on the estimated financial impact of the change in spill operations, among other factors, in the related fiscal year. In Fiscal Year 2018, Bonneville implemented a Spill Surcharge in the amount of approximately $10 million. On April 18, 2019, Bonneville held a public workshop to discuss the preliminary Fiscal Year 2019 Spill Surcharge formula. Bonneville expects to identify internal cost savings sufficient to entirely offset the expected cost of additional 2019 spring spill operations ($34.9 million); therefore, Bonneville is proposing that there be no Spill Surcharge in Fiscal Year 2019. Bonneville will accept public comments through May 2, 2019 and expects to issue a final decision regarding a Fiscal Year 2019 Spill Surcharge on May 16, 2019. For clarity, the changes in spill arising from the Oregon Federal District Court's ruling would not constitute an NFB Trigger Event. Furthermore, the NFB Adjustment and the Emergency NFB Surcharge would be available to address financial effects apart from any new spill operations arising from the Oregon Federal District Court's order.

The Final 2018-2019 Rates also include updated versions of the NFB Adjustment and Emergency NFB Surcharge included in prior rates. These rate adjustment features were designed to enable Bonneville to recover additional amounts or accelerate cost recovery during the 2018-2019 Rate Period, without a formal rate proceeding. These rate adjustment mechanisms would address unexpected costs or decreases in revenue (NFB Financial Effects) in a fiscal year arising from ESA litigation related to the Federal System. See "—Fish and Wildlife—The Endangered Species Act."

Under the Final 2018-2019 Rates, the NFB Adjustment was designed to increase the $300 million Power CRAC limit by an amount equal to forecast NFB Financial Effects and increase certain power and related rate levels so that the NFB Financial Effects would be recovered in the fiscal year following the fiscal year in which an event triggering the NFB Adjustment (an NFB Trigger Event) were to occur. The conditions under which the NFB Adjustment could have been triggered in the 2018-2019 Rate Period did not occur.

The Emergency NFB Surcharge in the Final 2018-2019 Rates was designed to enable Bonneville to increase certain power and related rate levels within the fiscal year in which an NFB Trigger Event were to occur to recover NFB Financial Effects expected to occur in such fiscal year. The Emergency NFB Surcharge was designed to take effect only within a fiscal year and only if the TPP for such fiscal year was forecast to be below 80 percent. Bonneville believes that it is very unlikely that the Emergency NFB Surcharge will trigger to increase rate levels in the remainder of Fiscal Year 2019.

In addition to the foregoing cost recovery adjustments, under the Final 2018-2019 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—Management's Discussion of Operating Results—Fiscal Year 2018," "—Bonneville's Use of Non-GAAP Financial Metrics," and "—Banking Relationship between the United States Treasury and Bonneville."

Historical PF Preference Rate Levels

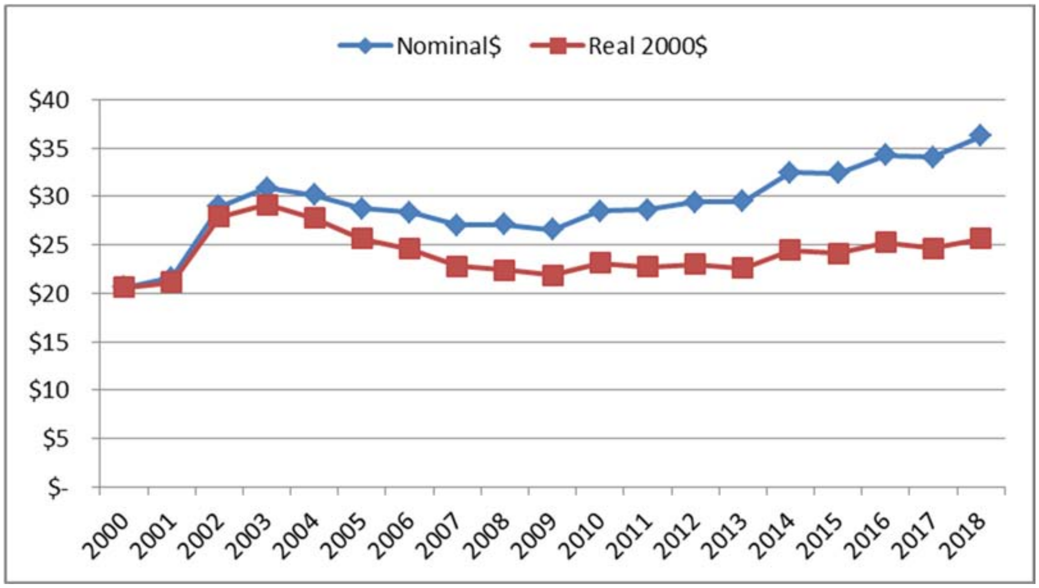
As shown in the following table, Bonneville's average PF Preference Rates have remained between $20 per megawatt hour and $37 per megawatt hour in nominal (actual) dollars, and between $20 per megawatt hour and $30 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2018. 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 from the effects of the West Coast Energy Crisis in 1999-2001. See "BONNEVILLE LITIGATION—Litigation and Related Disputes Arising from 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.

Historical Average PF Preference Rates

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

Per Megawatt Hour, Fiscal Years 2000—2018



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 $963 million in revenues from the sale of transmission and related services, or approximately 26 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 2018.

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 2018-2019), a large Preference Customer that purchases very little transmission for its own generating resources pays Bonneville approximately $4.23 per megawatt hour for transmission service and approximately $35.57 per megawatt hour for electric power.

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 260 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; 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, 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 generation, both inside and outside the Region. As reflected in the 2020-2021 Initial Rate Proposal, Bonneville expects to make transmission system investments in Fiscal Years 2019 through 2029 averaging approximately $470 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 and 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 $18 million in Fiscal Year 2018. Bonneville estimates that the transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments will be $15 million in Fiscal Year 2019 and approximately $17 million in Fiscal Year 2020.

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 would 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 is reviewing its expansion process and may implement changes to enhance the process in the future.

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, 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 maintenance 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's vegetation management program and related controls are reviewed by WECC every three years to ensure compliance with North American Electric Reliability Corporation Standard FAC-003. The most recent audit of Bonneville's vegetation management program by WECC was completed in June 2016 found no violations of the standard. 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. 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 that do not 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 reviewed by FERC 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, either through bilateral contracts or by (i) submitting to FERC for its approval an open access transmission tariff that substantially conforms or is superior to the *pro forma* tariff, and (ii) adopting transmission rates for third parties that are comparable to the rates the non-jurisdictional utility applies to itself. 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."

Because Bonneville is a non-jurisdictional utility, FERC Orders 888 and 890 have limited applicability to it. However, 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 voluntarily filed its tariff with FERC to obtain reciprocity status, however, in 2008, FERC declined to grant such status. In 2018, Bonneville and its long-term transmission customers reached a comprehensive settlement agreement regarding the open access transmission tariff. Pursuant to the settlement, Bonneville proposed that the Administrator adopt the agreed upon tariff terms and conditions (which are still modeled after FERC's *pro forma* tariff) during a proceeding initiated pursuant to the procedures in Section 212(i)(2)(A) of the Federal Power Act. In addition, Bonneville agreed to make changes to the tariff in the future pursuant to these procedures. Section 212(i)(2)(A), added to the Federal Power Act by EPA-1992, provides the Administrator with the option to initiate a regional hearing that largely follows Bonneville's rate case procedures (e.g., opportunities to present oral and written views on the record) to adopt transmission terms and conditions of general applicability (the Administrator may also use these procedures for FERC ordered transmission services under EPA-1992). Using Section 212(i)(2)(A) procedures, pursuant to the settlement agreement, provides the Administrator the flexibility to establish an open access tariff without having to rely on FERC approval. On March 1, 2019, Bonneville issued a final record of decision regarding adoption of the settlement agreement. All new and existing transmission contracts will be covered under the new tariff as of October 1, 2019. Bonneville's tariff includes certain features that seek to address Oversupply Management in times of high renewable energy generation and low energy loads. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Renewable Generation Development and Integration into the Federal Transmission System."

FERC issued "Order 889" in 1996 and "Order 717" in 2008. Each sets forth "standards of conduct" for jurisdictional transmission providers that have a power marketing affiliate or function. In general, these standards of conduct 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 voluntarily adheres to them. In the 1990s, Bonneville separated its transmission and power functions into separate business units. Bonneville continues to voluntarily adapt its operations to comply with

FERC's standards of conduct provisions. It currently operates in accordance with the standards of conduct set forth in Order 717.

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

Under the Northwest Power Act, Bonneville's transmission 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 approves and confirms 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 rates, equitably allocate the costs of the Federal Transmission System between federal and non-federal power.

Bonneville's Fiscal Years 2018-2019 transmission rates, which FERC approved in March 2018, reflect an average decrease of approximately 0.7 percent over Fiscal Years 2016-2017 rate levels.

Bonneville's Fiscal Years 2018-2019 transmission 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 Columbia River Power 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.

As proposed in the 2020-2021 Initial Rate Proposal, Bonneville's Fiscal Years 2020-2021 transmission rates reflect an average increase of approximately 3.6 percent over current rate levels.

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 2018. 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 2018)

Customer Name (Class)	Approximate % of Sales
Puget Sound Energy Inc. (IOU)	12%
PacifiCorp (IOU)	10%
Portland General Electric Company (IOU)	9%
Powerex Corp. (Power Marketer)	7%
Avangrid Renewables LLC (Wind Developer)	5%
Snohomish County PUD No. 1 (Preference)	5%
City of Seattle, City Light Dep't. (Preference)	5%
Pacific Northwest Generating Cooperative (Preference)	3%
Clark Public Utilities (Preference)	2%
Hermiston Power LLC (Power Marketer)	2%

(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.

Bonneville's Participation in Regional Transmission Planning

Bonneville is currently a member of "ColumbiaGrid," a regional transmission planning organization of eight Pacific Northwest utilities. ColumbiaGrid facilitates participation by its members in coordinated regional transmission planning but is not a Regional Transmission Organization ("RTO") under FERC policies.

Adding to its "Order 890" reforms, FERC provided transmission planning and cost allocation direction in its "Order 1000," dated July 21, 2011, and subsequent orders. Order 1000 requires jurisdictional utilities to participate in certain Regional transmission planning processes and in regional and interregional 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 comply by requiring compliance in order to obtain reciprocity and by indicating that it might exercise its authority under Federal Power Act section 211A to require such utilities to comply if they do not do so voluntarily.

Bonneville supports Regional transmission planning and increased interregional coordination as demonstrated by its participation in ColumbiaGrid. Bonneville believes, however, that certain provisions of Order 1000, mainly its mandatory cost allocation provisions, may conflict with Bonneville's statutory obligations and authority with respect to the Federal Transmission System.

In response to certain filings by ColumbiaGrid members for compliance related to the Order 1000 requirements, FERC ruled that Bonneville and other Regional non-jurisdictional utilities (i) can participate in Regional planning with other Northwest utilities, (ii) in participating in Regional planning, can choose not to be subject to mandatory cost allocation provisions and could either accept or reject a cost allocation for other utilities' proposed projects, and (iii) in participating in Regional planning on the basis of not being subject to mandatory cost allocation, would not be able to impose mandatory cost allocation of their proposed projects on other participating utilities. On May 12, 2016, FERC issued a final order regarding specifics related to implementation of Order 1000 for the ColumbiaGrid Region. Since that time, Bonneville has evaluated its expected level of participation in ColumbiaGrid's Order 1000 process as well as future involvement in the possible development of other regional planning organizations. At this time, Bonneville does not expect to participate in ColumbiaGrid's Order 1000 process. Bonneville has been in discussions with other entities in the Northwest regarding scoping the formation of a single organization that, if formed, would perform coordinated regional transmission planning but would not be an RTO under FERC policies. If Bonneville becomes a member of such new organization, it anticipates its participation with respect to the Order 1000 requirements to be similar in nature to what exists today through its participation in ColumbiaGrid. That is, Bonneville would participate in coordinated regional planning without being subject to mandatory cost allocation, and it would not be able to impose mandatory cost allocation of its proposed projects on other participating utilities.

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 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 and certain federal agency customers; (ii) to DSIs; (iii) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program; and (iv) as requested, to meet the net requirements of investor-owned utilities. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for 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.

Other Firm Power Rates

Bonneville's rates for other firm power sales within the Region are based on the cost of such resources as Bonneville determines are applicable to such sales. Bonneville also sells surplus firm power outside the Pacific Northwest, primarily to California, under short-term power sales that allow for flexible prices, or under long-term contract rates.

Surplus Energy

Energy that is surplus to the contracted-for requirements of Bonneville's Regional customers is priced in accordance with the statutory standards (contained in the Northwest Power Act) applicable to such sales, as discussed above. Such energy is available within and without the Pacific Northwest, with most sales being made to California markets.

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 limit the types of actions, remedies available, procedures to be followed, and the proper forum. 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

The United States Environmental Protection Agency ("EPA") will periodically identify Bonneville as one of multiple potentially responsible parties for costs associated with the investigation and remediation of "Superfund" sites pursuant to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"). In addition, state environmental agencies within Bonneville's service territory may also identify Bonneville as liable for contamination on its own or other third-party sites.

Currently, there are two Superfund sites and two federal facilities where Bonneville has been or may be identified as a Potentially Responsible Party for some of the contamination. There are also three other sites where Bonneville has been identified as a responsible party for some of the contamination. Bonneville's liability and costs are uncertain and speculative because of ongoing investigations into the extent of the contamination and subsequent apportionment of liability among multiple potentially responsible parties. However, based upon Bonneville's experience with other remediation actions, the total cost associated with these seven sites is expected to be less than $10 million.

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 could have 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 FERC exercising its authority under this provision in response to a complaint 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. 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, the United States Court of Appeals for the District of Columbia has ruled that neither the ERO nor FERC has jurisdiction to assess a monetary penalty against the United States, including Bonneville. Bonneville has received notices of alleged violations of certain mandatory reliability standards from WECC. WECC acts for the North American Electric Reliability Corporation ("NERC"), which is the ERO established by FERC. Bonneville is currently discussing the processing of these alleged violations with WECC.

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/Critical 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 proposes 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 Department of State. The 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 Department of State approved this negotiation authorization.

The United States and Canada began negotiations to modernize the Columbia River Treaty regime in May 2018, and the sixth round of negotiations was held in April 2019.

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 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.

President Trump's Fiscal Year 2020 Budget Request, submitted to Congress on March 11, 2019, included a specific proposal to "divest the transmission assets of the Power Marketing Administrations (PMAs), which include Southwestern Power Administration (SWPA), Western Area Power Administration (WAPA), and Bonneville Power Administration (BPA)." No further action has occurred on said proposal. Bonneville is unable to predict whether a similar proposal or any other proposal with respect to Bonneville will be included in the President's Fiscal Year 2021 Budget Request to Congress or the effects any such proposal would have on Bonneville or the Net Billed Bonds if enacted into law.

Federal Debt Ceiling

In order to fund its general operations, the United States relies on current receipts and the proceeds of debt obligations issued by the United States Treasury. In the past, the United States has narrowly avoided a situation where it would be unable to fund all of its operations because it reached the Congressionally-established debt ceiling. A future failure to raise the United States Treasury debt ceiling could result in default by the United States and have adverse implications on all funds held by the United States Treasury, including the Bonneville Fund. It is possible that actions taken or not taken by the United States Treasury or others at such times could materially affect Bonneville's operations and financial condition, including, among other things, restricting Bonneville's ability to borrow either short- or long-term from the United States Treasury and Bonneville's access to the Bonneville Fund to meet its cash payment obligations, including payments under the Net Billing Agreements, the 1989 Agreement, or the Direct Pay Agreements. The "Bipartisan Budget Act of 2018," enacted February 9, 2018, suspended the United States Treasury debt ceiling until March 1, 2019, at which point it was reinstated. As a result, the federal government cannot accrue debt beyond the amount that existed on March 1, 2019. The United States Treasury is currently employing a variety of procedures, known as "extraordinary measures", to avoid defaulting on the federal government's obligations. At this time, the Congressional Budget Office believes the extraordinary measures will be sufficient to sustain the United States Treasury through early fall of 2019, at which time the United States Treasury debt ceiling would need to be raised.

Government Shutdown and Effects on Bonneville

From time to time, including during Fiscal Year 2019, Congress has failed to timely enact federal budget 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.

Climate Change

Federal, regional, state, and international initiatives have been proposed or adopted to address global climate change by controlling or monitoring 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.

The EPA established a rule (the "Clean Power Plan"), under section 111(d) of the Federal Clean Air Act, which was expected to regulate carbon emissions in the electricity industry by setting "state-specific rate-based goals for carbon dioxide emissions from the power sector." However, the Clean Power Plan was challenged in court and the Supreme Court had placed a stay on the Clean Power Plan which prevented implementation until the legal challenge was complete. On March 28, 2017, President Trump issued an Executive Order entitled "Promoting Energy Independence and Economic Growth," which required that the EPA review the Clean Power Plan and related rules and agency actions in light of new energy policy objectives. In late 2017, the EPA issued a proposal to repeal the

Clean Power Plan and issued an advance notice of new proposed rulemaking. On August 21, 2018, the EPA proposed the "Affordable Clean Energy" rule to replace the Clean Power Plan. After a public comment period, the EPA held a public hearing to further discuss the proposed rule. The Affordable Clean Energy Rule would work to reduce carbon emissions by: (i) defining the "best system of emission reduction" for existing power plants as on-site, heat rate-rate efficiency improvements, (ii) providing states with a list of "candidate technologies" that can be used to establish standards of performance and be incorporated into state plans, (iii) incentivizing efficiency improvements at existing power plants, and (iv) giving states time and flexibility to develop their state plans. The EPA expects to finalize the Affordable Clean Energy rule in the second quarter of calendar year 2019.

In addition to the Clean Power Plan and proposed replacement with the Affordable Clean Energy rule, certain states have initiated clean power actions. For instance, the State of California initiated a cap and trade platform that became active in 2013. Bonneville sells substantial amounts of surplus electric power to parties that deliver it to the State of California.

Bonneville believes that direct effects on Bonneville of initiatives to reduce carbon emissions will or would be 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. 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 generation, it is unlikely that they will or would directly affect the cost of the output of the Federal System. In addition, Bonneville believes that it is likely that carbon-limiting actions will or would have the effect of increasing prices for electric power generally so the aggregate relative economic value of Bonneville's electric power probably would not decline as a result of such actions, all else being equal. Finally, there may also be pressure to retire certain high carbon intensity resources early, particularly coal-fired generation. Given the resource profile of the Federal System, it is unlikely that the resources that produce power marketed by Bonneville will be closed early as a result of climate change policy.

In addition, Bonneville believes that carbon limiting proposals could 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."

The physical effects of climate change could affect the generation capability of the Federal System to meet loads. Given the Federal System's reliance on precipitation and snow pack, climate change could affect the amount, timing, and availability of hydroelectric generation. 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."

Preparedness and Cyber Security

Two areas of increased attention in the electric power industry are managing risks to assure operational continuity and to assure cyber security. 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 such as a Regional earthquake. In October 2014, Bonneville completed modifications to a redundant system control center (to incorporate an adjoining emergency scheduling center) that is geographically separated from the existing control center, one east and one west of the Cascade Mountains, in areas not subject to the same 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 has taken several key steps and has expanded its cyber security capabilities. Bonneville has added permanent, full-time staff to its Office of Cyber Security with certified and trained professionals organized into cyber security teams 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 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 changes will help it face the challenge of increasing use of digital devices and increasing threats.

Renewable Generation Development and Integration into the Federal Transmission System

Bonneville is responsible for integrating most of the new generation projects that are located in the Region, and 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 recent power generation development in the Region has been from wind projects. Bonneville estimates that 5,082 megawatts of wind generation facilities are now interconnected to the Federal Transmission System and approximately 2,764 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 sale of seasonal surplus (secondary) 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 power 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. Bonneville now expects to see increasing solar power development. As with wind generation, solar power is subject to variability of generation so it presents transmission system integration challenges. However, solar output is easier to predict than wind generation; thus, Bonneville believes that integrating solar will be substantially less challenging. Bonneville expects that it will integrate into the Federal Transmission System approximately 100 annual average megawatts of solar resources in aggregate by Fiscal Year 2020.

Western Energy Imbalance Market

In July 2018, Bonneville initiated a public process to determine how and under what conditions it could join the Cal-ISO's Western Energy Imbalance Market ("EIM"). The EIM is 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. 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. In the summer of 2019, Bonneville expects to issue a decision document describing Bonneville's intent to join the EIM, subject to certain principles. If Bonneville proceeds with joining the EIM, Bonneville would enter into an implementation agreement with the Cal-ISO and subsequent agreements as Bonneville moves toward implementation in Spring 2022.

If Bonneville joins the EIM, its current estimate of start-up costs is approximately $35 million (primarily related to grid modernization). In addition, once operational, Bonneville's current estimate of annual costs to Power Services and Transmission Services to support the EIM effort is approximately $6 million. Due to the more efficient dispatching and reduced costs by increasing the efficiency of serving load imbalances, Bonneville currently estimates that Power Services' net revenues would increase by approximately $10 million per year.

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 and may be changed by the DOE and subsequently by the United States Office of Management and Budget. The Office of Management and Budget, after providing opportunity for Bonneville to respond to proposed changes, 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.

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, 2018, Bonneville had repaid $14.9 billion of principal of the Federal System investment and had approximately $2.17 billion principal amount outstanding with regard to such appropriated investments and $5.53 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 $4 million and $57 million per year over the next ten years.

Internal Guidance Affecting Bonneville Financial Operations

In January 2018, Bonneville published its updated Strategic Plan that identifies 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 that Bonneville expects will be its central reference point over the next five years: (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.

The supporting Financial Plan, published in February 2018, outlines the three financial health objectives that will guide Bonneville's other strategies. The financial health objectives focus on (i) cost management discipline, (ii) financial resiliency, and (iii) independent financial health assessment and are designed to support Bonneville's ability to deliver on its mission and meet its multiple statutory obligations under various conditions. Bonneville began holding public meetings in March 2018 to determine how to implement different aspects of the Strategic Plan and Financial Plan.

Since release of the plans, Bonneville has made progress towards each of its financial health objectives. In Fiscal Years 2020 and 2021, Bonneville expects to significantly beat its strategic cost management goals. Bonneville's internal costs included in the 2020-2021 Initial Rate Proposal are $143 million per year below the established financial health objective and $66 million per year below the prior rate period. Bonneville also refined its Financial Reserves Policy and proposed that for the 2020-2021 Rate Period it would collect up to $30 million per year in Power Services' rates and up to $15 million in Transmission Services' rates per year to replenish financial reserves if financial reserves are below 60 Days Cash on Hand ($300 million for Power Services and $94 million for Transmission Services) at September 30, 2019 or September 30, 2020. This mechanism referred to herein as the Financial Reserves Policy Surcharge is in addition to maintaining the legacy Cost Recovery Adjustment Clause rate collection mechanisms. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021."

Bonneville's Treasury Borrowing Authority

Bonneville is authorized to issue and sell to the United States Treasury, and to have outstanding at any one time, up to $7.7 billion aggregate principal amount of bonds. Of the $7.7 billion in borrowing authority that Bonneville has with the United States Treasury, bonds in the principal amount of $5.53 billion were outstanding as of the end of Fiscal Year 2018. 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 $7.7 billion in United States Treasury borrowing authority, $1.25 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 $6.45 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 2018, the interest rates on the outstanding bonds ranged from 1.1 percent to 5.9 percent with a weighted average interest rate of approximately 3.2 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2018, Bonneville's outstanding bonds issued to the United States Treasury included $1.46 billion in variable rate bonds at an average interest rate of 2.26 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 can be 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 to borrow for operating expenses, an ability that Bonneville had lacked previously. Under the short-term expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating 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 $7.7 billion 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 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, 2018, aggregate Non-Federal Debt outstanding was approximately $7.7 billion. By way of comparison, as of September 30, 2018, the principal amount of unrepaid appropriations for Federal System investments was approximately $1.8 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was $5.53 billion. Described below are the currently outstanding forms of Non-Federal Debt. For a description of possible Non-Federal Debt transactions in the near future, see "—Bonneville's Capital Program—Possible Non-Federal Debt Activities in the Near Future."

Net Billed Bonds

Energy Northwest bonds issued for the Net Billed Projects represent the largest single component of Non-Federal Debt: $5.2 billion out of a total of $7.7 billion aggregate Non-Federal Debt, as of September 30, 2018.

As discussed previously in this Appendix A, 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.

Assistance in Reducing Certain Power Rate Impacts. The issuance by Energy Northwest of refinancing Net Billed Bonds under the Regional Cooperation Debt initiative has also enabled Bonneville to reduce the effects of certain upward pressures on near-term Power Services rates. These pressures arise from a decision by Bonneville in Fiscal Year 2015 to pay future energy efficiency program costs as an item of current expense from and after Fiscal Year 2016. Bonneville's prior practice was to capitalize certain costs of its energy efficiency program and finance the costs over twelve-year periods through borrowings from the United States Treasury. In developing its proposal for the Final 2016-2017 Rates, Bonneville anticipated (i) the issuance of the refinancing Net Billed Bonds by Energy Northwest in April 2016 and April 2017 and (ii) the use of a portion of the resulting anticipated accumulation of balances in the Bonneville Fund as a source to offset some of the Power Services rate impacts of the transition of energy efficiency costs to expense. In developing its proposal for the Final 2018-2019 Rates, Bonneville anticipated (i) the issuance of the refinancing Net Billed Bonds by Energy Northwest in Fiscal Year 2018 and Fiscal Year 2019 and (ii) the use of a portion of the resulting anticipated accumulation of balances in the Bonneville Fund as a source to offset some of the Power Services rate impacts of the transition of energy efficiency costs to expense. These actions enabled Bonneville to accumulate additional cash balances in the Bonneville Fund to cover approximately $72 million of energy efficiency program expense in Fiscal Year 2016, $68 million in Fiscal Year 2017, and $121 million in Fiscal Year 2018.

Bonneville Cash Management to Enable Additional Interest Expense Savings. As part of its coordinated actions to prepay high interest Federal Appropriations Repayment Obligations, in Fiscal Year 2018, Bonneville also used certain available financial reserves in the amount of $82 million to advance by one year the prepayment of a like amount of high interest Federal Appropriations Repayment Obligations which prepayment would otherwise have occurred at the end of Fiscal Year 2019. The reserves are unexpended amounts that were derived from the electric power prepayment program. Bonneville estimates that the foregoing planned use of electric power prepayment balances will reduce interest expense in Fiscal Year 2019 by approximately $3 million. In Fiscal Year 2019, Bonneville expects to expend the remaining $82 million balance of electric power prepayments on Federal System hydroelectric facility investments; therefore, such amounts are not expected to be available for early repayment of high interest Federal Appropriations Repayment Obligations in future years. See "—Electric Power Prepayments."

Columbia Generating Station Decommissioning and Restoration Cost. In addition to payment of debt service related to Net Billed Bonds, amounts expected to be necessary to decommission Columbia Generating Station have been and will be recovered under the Net Billing Agreements and borne by Bonneville. See the Official Statement under the heading "ENERGY NORTHWEST—The Columbia Generating Station—Decommissioning and Site Restoration." Bonneville makes monthly contributions to the Columbia Generating Station decommissioning trust fund to meet the amount expected to be required to decommission the plant and restore the site. Such costs are recovered by Bonneville through its Power Services' rates. For more details regarding the Asset Retirement Obligation and Decommissioning and Site Restoration Trust Fund related to Columbia Generating Station, please see Appendix B-1 to the Official Statement (Note 5 to Financial Statements). The total amounts expected to be needed to decommission the plant and restore the site could change based on a variety of factors, including total expected costs to decommission the plant, discount rate applied, inflation factors, decommissioning method, and the decommissioning date. Based on forecast earnings growth and inflation, Bonneville believes that the current trust fund balances and contribution levels will be sufficient to ensure adequate funding would be available when needed. Bonneville continues to evaluate the contribution levels, but does not expect to make any adjustments to its trust fund contribution levels in Fiscal Year 2019 or during the 2020-2021 Rate Period.

On March 31, 2019, Bonneville recorded an increase of $595 million (to $765 million) to its asset retirement obligation related to the Columbia Generating Station. Due to differences in applicable accounting guidance, Bonneville's current estimate of its Columbia Generating Station asset retirement obligation recorded in the audited financial statements of the Federal System differs from Energy Northwest's current estimate of its ARO liability. See the Official Statement under the heading "ENERGY NORTHWEST—The Columbia Generating Station—Decommissioning and Site Restoration."

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 outstanding short-term lease-purchase arrangements with the Port of Morrow, Oregon (the "Port of Morrow") and the Idaho Energy Resources Authority ("IERA") and long-term lease-purchase arrangements with Northwest Infrastructure Financing Corporation, the Port of Morrow, and the IERA.

The aggregate principal amount of outstanding bank loans and publicly-issued bonds associated with Bonneville's lease-purchase agreements, together with the principal amount associated with certain pre-existing capital leases, was $2.2 billion as of September 30, 2018. Of the foregoing amount, the aggregate outstanding principal amount of publicly-issued lease-purchase bonds was approximately $1.1 billion. Approximately $1 billion of the remaining aggregate outstanding principal amount relates to bank loans associated with short-term lease-purchase agreements that terminate in Fiscal Year 2020 through Fiscal Year 2025 which Bonneville expects to fund from publically-issued lease-purchase bonds.

Bonneville expects to continue to participate in financings where short-term lease-purchases secure construction loans that are repaid with the proceeds of long-term bonds secured by subsequent long-term lease-purchases. See "—Bonneville's Capital Program—Possible Non-Federal Debt Activities in the Near Future."

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. The offsetting prepayment credits are set at $3 million per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028.

Bonneville expects to expend the remaining $82 million in prepayments on Federal System hydroelectric facility investments in Fiscal Year 2019.

As of September 30, 2018, outstanding Non-Federal Debt associated with electric power prepayments was $248 million.

Resource Acquisitions

In 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, 2018, outstanding Non-Federal Debt for generating resource acquisitions was $84 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." Bonneville has no current plans to enter into new capitalized resource acquisition agreements.

The following table depicts the types and amounts of Non-Federal and Federal Debt outstanding as of the end of each of Fiscal Years 2016 through 2018. Any discrepancies in totals for figures portrayed in this table are due to rounding.

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Non-Federal and Federal Debt, Fiscal Years 2016-2018
(Dollars in millions)

Non-Federal and Federal Debt Outstanding

Projects Financed with Non-Federal Debt	**2018**	**2017**	**2016**
Non-Federal Generation			
Columbia Generating Station	$3,469	$3,854	$3,636
Cowlitz Falls Project	72	76	79
Terminated Generation			
Nuclear Project No. 1	796	838	865
Nuclear Project No. 3	914	1,044	1,068
Northern Wasco Hydro Project	11	13	14
Lease-Purchase Program/Capital Leases	2,200	2,170	2,069
Customer prepaid power purchases	248	267	285
Total Non-Federal Debt	$7,710	$8,262	$8,016
Federal Debt			
Borrowings from U.S. Treasury	5,531	5,009	4,759
Federal appropriations	1,355	1,583	2,430
Federal appropriations (not yet scheduled for repayment)	437	446	436
Total Federal Debt	$7,322	$7,038	$7,625
Total Debt	**$15,032**	**$15,300**	**$15,641**

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 Net Billed Project costs (including debt service on the Series 2019-A/B 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 2019-A/B 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 2014-2018. 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)

	2014	2015	2016	2017	2018	Total
Transmission[2]	$613	$734	$552	$440	$411	**$2,750**
Federal System Hydro	173	167	187	207	199	**933**
Energy Efficiency[3]	78	87	0	0	0	**165**
Fish and Wildlife	37	21	16	5	31	**110**
Facilities, Information Technology, Security[2]	28	28	22	10	14	**102**
Total	**$929**	**$1,037**	**$777**	**$662**	**$655**	**$4,060**

(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.
(3) Beginning in Fiscal Year 2016, Bonneville began expensing energy efficiency program costs.

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 2014 through Fiscal Year 2018. 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)

	2014	2015	2016	2017	2018	Total
Borrowing from United States Treasury	$544	$647	$504	$521	$498	**$2,714**
Lease-Purchases[2]	248	249	255	134	77	**963**
Projects Funded in Advance	7	2	3	7	65	**84**
Reserve Funding	15	15	15	0	15	**60**
Electric Power Prepayments[3]	115	124	0	0	0	**239**
Total	**$929**	**$1,037**	**$777**	**$662**	**$655**	**$4,060**

(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 Prioritization 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 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 Willamette BiOp. Bonneville's capital expenditures also include information technology, certain heavy equipment and certain costs related to financing.

In 2016, Bonneville introduced its Asset Management Key Strategic Initiative designed to bring a renewed focus to asset management. Central to the renewed focus is the effort to more closely align Bonneville's asset management processes 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 and asset plans. In 2017 and 2018, Bonneville developed strategic asset management plans and asset plans. The strategic asset management plans provide a medium to long-term 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 were developed from the strategic asset management plans using a value-based analytical methodology to prioritize competing investment needs. This prioritization seeks to balance the often competing goals of keeping Bonneville's power and transmission rates as low as possible, 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 subject to prioritization.

Most of Bonneville's capital investments involve renewals, upgrades and replacement of existing facilities and are incremental in character. Occasionally, Bonneville makes determinations that involve substantial long-term commitments for new capital investments. For example, in May 2017 Bonneville determined not to proceed with the construction of a new transmission line and related facilities in western portions of Washington State and Oregon after multiple years of evaluation. The capital cost of this project was expected to exceed $1 billion over a five-year period. Through September 2017, Bonneville had recorded approximately $130 million as construction work in progress related to project planning and preliminary design costs for the proposed transmission line. Such costs were reclassified to a regulatory asset and will be amortized and recovered in the five-year period beginning in Fiscal Year 2020.

In connection with developing the 2020-2021 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)

	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**Total**
Transmission	$380	$475	$468	$463	$456	$465	$474	$483	$493	$502	$511	**$5,170**
Fed System Hydro	195	238	256	281	300	306	313	319	326	333	340	**3,207**
Fish and Wildlife	44	47	48	43	43	40	40	40	40	40	15	**440**
Facilities, Information Technology, Security	51	57	51	44	68	76	28	50	50	49	50	**574**
AFUDC[(1)]	28	32	30	31	32	32	33	34	34	35	36	**357**
Total	**$698**	**$849**	**$853**	**$862**	**$899**	**$919**	**$888**	**$926**	**$943**	**$959**	**$952**	**$9,748**

(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 $1.2 billion in additional capital requirements from July 2018 through June 2030. 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 "—Possible Non-Federal Debt Activities in the Near Future." The Forecast Capital Spending table above also does not include investments related to the Columbia River Fish Mitigation program. 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, 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 planned for and assumptions made when developing the 2020-2021 Initial Rate Proposal will enable Bonneville to meet its capital and financial liquidity needs through at least Fiscal Year 2023.

Bonneville also established a new Leverage Policy guiding Bonneville's debt management practices. The Leverage Policy, like the Financial Reserves Policy, is implemented through development of Bonneville rates. The Leverage Policy requires each business line maintain or decrease its financial leverage over time and sets a target of 75-85% leverage by Fiscal Year 2028 and a long-term target of 60-70%. Finally, under the Regional Cooperation Debt initiative, the Energy Northwest Board adopted a motion supporting the refinancing of up to an additional $3.5 billion of Net Billed Bonds through 2030 to provide for the funding of capital investments in the Federal Columbia River Power System in Fiscal Years 2021 through Fiscal Year 2030. The expected extension of the Regional Cooperation Debt efforts will provide flexibility for Bonneville to shape and stabilize capital related costs over time enabling it to pay down, in a reasonable amount of time, Federal Repayment Obligations. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions" and "–Possible Non-Federal Debt Activities in the Near Future.'

Possible Non-Federal Debt Activities in the Near Future

In carrying out its capital financing strategy, Bonneville is planning to or may seek to enter into Non-Federal Debt arrangements in the near future.

<u>Future Lease-Purchases</u>. Bonneville expects that prior to September 2019 the Port of Morrow will issue about $100 million of Bonneville-supported lease-purchase bonds (federally taxable) to refinance certain transmission facilities that it initially funded through a short-term lease-purchase construction bank facility. The debt service of such bonds will be secured by Bonneville's rental payments under a long-term lease-purchase agreement. The Port of Morrow has taken no official action to authorize such additional bonds.

For future fiscal years, Bonneville assumes that the amount of long-term lease-purchase arrangements to refinance certain transmission facilities funded through short-term lease-purchase construction bank facilities and the bonds secured thereby could be up to $350 million per year on average through Fiscal Year 2022. It is possible that the Port of Morrow, IERA, or others could enter into such short-term bank facilities and/or issue such publicly-offered bonds.

Possible Additional Net Billed Bonds and Net Billed Project Debt Restructuring. 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 $1.2 billion from July 2018 through June 2030. Additional Net Billed Bonds for additional capital investments for Columbia Generating Station may be issued thereafter. In addition, Bonneville expects that it and Energy Northwest will continue to restructure Net Billed Bond debt (which includes the Series 2019-A/B Bonds) 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. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

Possible Additional Electric Power Prepayments. While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use Electric Power Prepayments, a form of Non-Federal Debt, to meet some of its capital funding needs. See "—Bonneville's Non-Federal Debt."

Possible Additional Resource Acquisitions. While Bonneville has no current plans to do so, Bonneville may seek to use this form of Non-Federal Debt to acquire electric power generating and conservation resources. See "—Bonneville's Non-Federal Debt."

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 Payment 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 levels 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 $243 million, $143 million, and $32 million, respectively, in Fiscal Year 2018.

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 $318 million to $409 million in scheduled payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses, through Fiscal Year 2023. Bonneville expects that it will renew and extend the direct funding agreements with the Corps and the Department of Interior prior to the expiration dates of the respective agreements.

As part of Bonneville's increased commitments for capital facilities to assist in Federal System fish and wildlife activities, in particular under the Columbia Basin Fish Accords, Bonneville has agreed in principle to establish a mechanism to use direct funding to finance certain capital expenditures of the Corps at its Federal System Hydroelectric Projects. Under this arrangement, Bonneville will borrow funds from the United States Treasury and transfer the funds to the Corps to make the expenditures. The debt service on the amounts borrowed from the United States Treasury would be payable by Bonneville from "net proceeds." See "—Order in Which Bonneville's Costs Are Met."

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 2018 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments to the U.S. Treasury in the amount of $862 million in Fiscal Year 2018, approximately $275 million was for the amortization ahead of schedule of certain Federal Appropriations Repayment Obligations. Bonneville plans to make similar advance amortization payments to the United States Treasury at the end of Fiscal Year 2019. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

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 2019-A/B 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 2019-A/B 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. Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were $18 million in Fiscal Year 2018 and will be $15 million in Fiscal Year 2019.

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 Agreement, or 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 2018, approximately $191 million in Total Financial Reserves (cash, investments in United States Treasury market-based special securities and deferred borrowing) were derived from Power Services' rates and operations and $648 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 2018." 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 2018, Bonneville had $551 million 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—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2020-2021" and "—Fiscal Year 2019 Expectations and Related Information," and POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019." 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.

Reserves Not Available for Risk. For ratemaking purposes, Bonneville uses a financial metric it refers to as "Reserves Not Available for Risk," or "RNAR," as a measure of financial reserves that are not available for risk. While the RNAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RNAR metric provides a sound measure of Bonneville's reserves derived from operations that are committed for certain purposes and are not available for risk. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2018 Financial Results." The RNAR metric represents amounts in, or reliably available to, the Bonneville Fund which are generated through normal operations but are committed for other purposes (including deposits from third parties, capital funds drawn in advance, borrowings for expenses and other amounts deemed by Bonneville not to be available for risk).

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 deferred borrowing from the United States Treasury, all of which are available to meet Bonneville's current expenditure needs. 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 2018, Total Financial Reserves were $840 million. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Year 2020-2021" and "—Fiscal Year 2018Financial Results," and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2018-2019."

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 Expenses divided by 360. The information is unaudited.

Bonneville's Fiscal Year-End Financial Reserves
Fiscal Years 2014-2018
(Dollars in millions)

Fiscal Year	Total Financial Reserves	Reserves Available for Risk[1]	U.S. Treasury Short-Term Line	Days Liquidity on Hand[2]
2014	1,224	784	750	317
2015	1,187	845	750	347
2016	724	602	750	281
2017	766	568	750	258
2018	840	551	750	254

(1) Beginning in Fiscal Year 2018, Bonneville management made a change to the RAR calculation to exclude short-term carryover cash flow effects such as accruals for revenues earned in Fiscal Year 2018 but not received until Fiscal Year 2019 and expenses incurred in Fiscal Year 2018 that were not paid until Fiscal Year 2019 to provide a more clear reflection of amounts available for risk mitigation at September 30. The Fiscal Year 2018 RAR amount of $551 million excludes approximately $72 million of accruals for revenues and expenses that would have been included in RAR calculations in prior years. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2018 Financial Results.

(2) The calculation of Days Liquidity on Hand is (RAR + United States Treasury Short-Term Line) / (Operating Expenses / 360).

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 cleared 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.

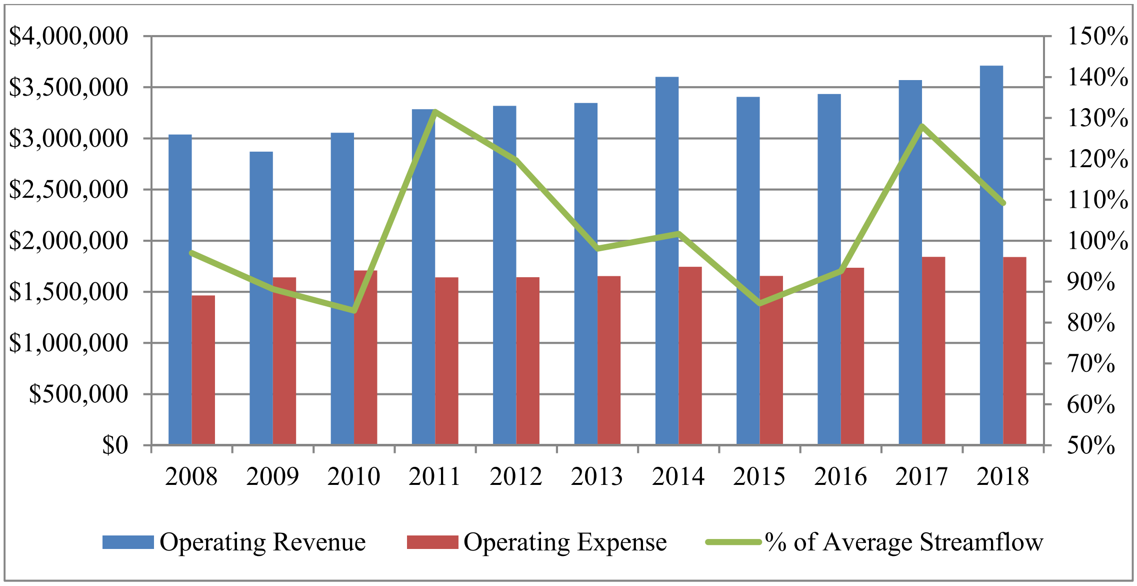
Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow

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. 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 (secondary) 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/Critical 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 (secondary) energy. In establishing rates for the 2018-2019 Rate Period, Bonneville assumed that revenues from net secondary energy sales would average approximately \$342 million per fiscal year of the rate period, assuming average streamflow. For reference, \$342 million is approximately 11 percent of Bonneville total revenues of approximately \$3.7 billion (Fiscal Year 2018).

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.

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 30) 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 2018, Bonneville made $40 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. See the Official Statement under the heading "ENERGY NORTHWEST—Retirement Plans and Other Post-Employment Benefits."

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2016 through 2018 are set forth in the following "Federal System Statement of Revenues and Expenses (Unaudited)" table. Such data have been derived from the annual audited financial statements of the Federal System 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 operation and maintenance costs of the Fish and Wildlife Service.

Federal System Statement of Revenues and Expenses
(Unaudited)

As of Sept. 30 – Dollars in millions	**2018**	**2017**	**2016**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities [(1)]	$2,155	$2,125	$2,070
Direct Service Industrial Customers	25	11	19
Northwest Investor-Owned Utilities	92	96	76
Sales outside the Northwest Region [(2)]	387	307	238
Book-outs [(3)]	(20)	(21)	(22)
Total Sales of Electric Power	2,639	2,518	2,381
Transmission [(4)]	963	964	947
Fish Credits and other Revenues [(5)]	108	88	105
Total Operating Revenues	3,710	3,570	3,433
Operating Expenses:			
Bonneville O&M [(6)]	1,150	1,135	1,114
Purchased Power [(3)]	159	147	112
Corps, Reclamation, and Fish & Wildlife Service O&M [(7)]	418	416	402
Non-Federal entities O&M — net billed [(8)]	262	313	254
Non-Federal entities O&M — non-net billed [(9)]	28	28	37
Total Operation and Maintenance	2,017	2,039	1,919
Net billed Debt Service	258	232	240
Non-net billed Debt Service	9	9	9
Non-Federal Projects Debt Service [(10)]	267	241	249
Federal Projects Depreciation	507	485	471
Residential Exchange [(11)]	241	219	219
Total Operating Expenses	3,032	2,984	2,858
Net Operating Revenues	678	586	575
Interest Expense:			
Appropriated Funds	67	125	203
Long-term debt	236	220	200
Capitalization Adjustment [(12)]	(65)	(65)	(65)
Allowance for funds used during construction	(31)	(33)	(40)
Net Interest Expense [(13)]	207	247	298
Net Revenues/(Expenses)	**471**	**$339**	**$277**
Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	9,597	9,760	9,642

[(1)] This customer group includes Preference Customers (municipalities, public utility districts, and electric cooperatives in the Region) and federal agencies. This amount reflects refunds to Preference Customers arising from past overpayments of Residential Exchange Program benefits to Regional IOUs. Refund amounts recorded in Fiscal Year 2018 were $77 million (see footnote (11) below).

(2) In general, revenues from Sales outside the Northwest Region are derived from seasonal surplus (secondary) energy and firm long-term sales. The availability of seasonal surplus (secondary) 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/Critical Water. In almost all years, except when streamflow is near Low Water Flows/Critical Water, the amount of seasonal surplus (secondary) energy that Bonneville exports is greater than firm sales exports. Revenues from seasonal surplus (secondary) 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 $73 million, $54 million, and $70 million in Fiscal Years 2016, 2017, and 2018, 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 operation 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 operation 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 operation 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 operation 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) Non-Federal Projects Debt Service includes payments (and net billing credits when in effect) by Bonneville for all or a part of the generating capability of, and the related debt service, including interest, for Energy Northwest's Net Billed Projects described in footnote (8) above, and the generating capability of other small projects which Bonneville has acquired.

(11) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services" and "—Residential Exchange Program" and see "—Management's Discussion of Operating Results." Bonneville's 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 2018, the Residential Exchange Program payments were $241 million. In Fiscal Year 2018, Bonneville also provided refunds in an aggregate amount of $77 million to qualifying Preference Customers for overpayments ("Refund Amounts") Bonneville made to Regional IOUs for the period July 1, 2001 through September 30, 2011 under the original Residential Exchange Program Settlement Agreements, which were invalidated by the Ninth Circuit Court in May 2007. Bonneville recognizes a refund for Refund Amounts recovered from Regional IOUs in the rate setting process and returned to Preference Customers and will do so through Fiscal Year 2019, at which time all

overpayments will be fully recovered. See “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Residential Exchange Program.”

(12) 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.

(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.

Management’s Discussion of Operating Results

Fiscal Year 2018

In Fiscal Year 2018, Bonneville made its scheduled United States Treasury payments on time and in full for the 35th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $840 million, which is an increase of approximately 10 percent from the prior fiscal year.

In Fiscal Year 2018, Federal System net revenues were $471 million, an increase of approximately $132 million from net revenues of $339 million in Fiscal Year 2017.

In Fiscal Year 2018, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $3.7 billion, which is about $141 million greater than the prior fiscal year. Power Services’ gross sales increased $120 million, or approximately 5 percent, in Fiscal Year 2018 compared to Fiscal Year 2017 primarily due to two key factors: (i) firm power sales increased $31 million due to the Power Services’ rate increase that went into effect on October 1, 2017 and (ii) seasonal surplus (secondary) sales increased $88 million in Fiscal Year 2018 due to: (a) above-average hydro power supply sales in the second quarter of Fiscal Year 2018 and (b) slightly higher short-term energy market prices that Bonneville was able to obtain for the sale of seasonal surplus (secondary) 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 2018 runoff volume at The Dalles Dam was 119 MAF. The full Fiscal Year 2018 volume finished at 145 MAF, a decrease of 25 MAF from the 170 MAF attained in Fiscal Year 2017, and above the historical average of 132 MAF.

United States Treasury credits increased $16 million in Fiscal Year 2018 compared to Fiscal Year 2017. The increase was primarily due to decreased streamflow and higher generation resulting in higher replacement power purchases.

Operating expense increased $48 million in Fiscal Year 2018 from Fiscal Year 2017. Operations and maintenance expense decreased $12 million, or one percent, from the prior fiscal year primarily due to a decrease of $50 million in Columbia Generating Station plant costs since Fiscal Year 2018 was not a refueling year. This increase was offset in part by (i) a scheduled increase of $22 million in Residential Exchange Program benefits and (ii) an increase of $13 million in contributions for post-retirement benefit programs and pension benefit costs resulting from changes to cost factors developed by the Office of Personnel Management.

Purchased power expense, including the effects of bookouts, increased $12 million for Fiscal Year 2018 as compared to Fiscal Year 2017 mainly due to (i) above-average market prices experienced during the summer and (ii) an 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.

Non-Federal Projects Debt Service expense increased $26 million, or 11 percent, from the prior fiscal year, primarily due to the scheduled repayment of certain outstanding Net Billed Bonds for Columbia Generating Station.

Depreciation and amortization increased $22 million, or five percent, from the prior fiscal year, primarily due to increased depreciation rates implemented as part of a new depreciation study completed in February 2018.

At the end of Fiscal Year 2018, RAR for Power Services operations were $13 million, a decrease of 88 percent from the prior fiscal year, and RAR for Transmission Services operations were $538 million, an increase of 16 percent from the prior fiscal year. Aggregate Bonneville RAR were $551 million, a decrease of three percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." Any reallocation of RAR from Transmission Services to Power Services would be applied prospectively starting in Fiscal Year 2019. Bonneville does not plan to restate any prior year-end business line RAR balances. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2019 Expectations and Related Information."

Fiscal Year 2017

In Fiscal Year 2017, Bonneville made its scheduled United States Treasury payments on time and in full for the 34th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $766 million, which is an increase of approximately 6 percent from the prior fiscal year.

In Fiscal Year 2017, Federal System net revenues were $339 million, an increase of approximately $62 million from net revenues of $277 million in Fiscal Year 2016. Bonneville reported Adjusted Net Revenues of $5 million for Fiscal Year 2017.

In Fiscal Year 2017, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $3.5 billion, which is about $157 million greater than the prior fiscal year.

Power Services' gross sales increased $137 million, or approximately 6 percent, in Fiscal Year 2017 compared to Fiscal Year 2016 primarily due to two key factors: (i) firm power sales increased $29 million due to increased load shaping revenue from the colder-than-average weather in the Pacific Northwest and increased revenues from DSIs resulting from the slight increase in load commitment at the IP Rate (increase from 10 annual average megawatts to 25 annual average megawatts that went into effect in March 2017) and (ii) seasonal surplus (secondary) sales increased $108 million in Fiscal Year 2017 due to: (a) above-average hydro power supply sales and (b) slightly higher short-term energy market prices that Bonneville was able to obtain for the sale of seasonal surplus (secondary) 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 2017 runoff volume at The Dalles Dam was 137 MAF. The full Fiscal Year 2017 volume finished at 170 MAF, an increase of 47 MAF from the 123 MAF attained in Fiscal Year 2016, and well above the historical average of 132 MAF.

Transmission Services gross sales increased $19 million in Fiscal Year 2017 compared to Fiscal Year 2016, primarily due to increased sales of short-term transmission and ancillary services related to the increase in streamflow and higher federal generation as described immediately above.

United States Treasury credits decreased $19 million in Fiscal Year 2017 compared to Fiscal Year 2016. The decrease was primarily due to increased streamflow and higher generation resulting in lower replacement power purchases.

Operating expense increased $127 million in Fiscal Year 2017 from Fiscal Year 2016. Operations and maintenance expense increased $85 million, or four percent, from the prior fiscal year primarily due to: (i) an increase of $59 million in Columbia Generation Station plant costs due to higher maintenance and costs related to biennial refueling in Fiscal Year 2017, (ii) an increase of $16 million in Bureau of Reclamation's operations and maintenance costs related to work at the Grand Coulee Dam Third Power Plant, (iii) an increase of $24 million in Power Services' transmission acquisition costs due to increased third-party wheeling costs for delivering energy to transfer service customers, and (iv) a decrease of $17 million in corporate costs due to cost management initiatives and lower contributions for post-retirement benefits.

Purchased power expense, including the effects of bookouts, increased $36 million for Fiscal Year 2017 as compared to Fiscal Year 2016 primarily due to an 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.

Depreciation and amortization increased $14 million, or three percent, from the prior fiscal year, primarily due to increased completed plant in service for Power Services and Transmission Services construction projects.

At the end of Fiscal Year 2017, RAR for Power Services operations were $105 million, a decrease of 34 percent from the prior fiscal year, and RAR for Transmission Services operations were $463 million, an increase of four percent from the prior fiscal year. Aggregate Bonneville RAR were $568 million, a decrease of six percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." Any reallocation of RAR from Transmission Services to Power Services would be applied prospectively starting in Fiscal Year 2019. Bonneville does not plan to restate any prior year-end business line RAR balances. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2019 Expectations and Related Information."

In Fiscal Year 2013 through Fiscal Year 2017, Bonneville utilized and reported a financial metric, "Adjusted Net Revenues." While the Adjusted Net Revenues metric was not a measure in accordance with GAAP and was unaudited, Bonneville management believed the use and reporting of Adjusted Net Revenues assisted in reflecting Bonneville's financial performance for day-to-day operations in such fiscal years. The Adjusted Net Revenues metric was net revenues after removing the non-operating effects on Bonneville of certain debt management and related actions with respect to Net Billed Bonds under the Regional Cooperation Debt approach. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

The first phase of Regional Cooperation Debt occurred under the Debt Optimization Program (between 2001 and 2009) under which Energy Northwest and Bonneville worked together to refinance certain maturities of Net Billed Bonds so that the weighted average maturities more closely matched the originally expected useful lives of the related Net Billed Project facilities. These debt management actions freed up Bonneville revenues to replenish available United States Treasury borrowing capacity by extending into the future the repayment dates of debt for the Net Billed Projects. The resulting reductions in intervening debt payments (in the period between the dates the Energy Northwest debt was initially due to be repaid and the dates that such refinanced debt was re-set to be repaid) resulted in funds becoming available to repay principal of Bonneville's then-outstanding United States Treasury debt.

Net Billed Project debt expense is recorded over the term of the related outstanding debt. The lower Net Billed Project debt expense due to the Debt Optimization Program resulted in higher net revenues than otherwise would have been reported in the affected fiscal years absent the debt management actions. As the Energy Northwest debt that was issued for the refinancing under the Debt Optimization Program reaches maturity, as is now occurring, the converse of the original effects of Debt Optimization on financial reporting is also occurring: Net Billed Project debt expense is higher than, and Federal System net revenues are lower than, would have been the case without Debt Optimization.

Bonneville and Energy Northwest initiated another phase of Regional Cooperation Debt beginning in 2014. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions." The Regional Cooperation Debt transactions in Fiscal Years 2014 through 2017 had the effect of lowering Net Billed Project debt expense and resulted in higher net revenues than otherwise would have been reported in Fiscal Years 2014 through 2017 absent the Fiscal Years 2014 through 2017 Regional Cooperation Debt management actions.

Fiscal Year 2016

In Fiscal Year 2016, Bonneville made its scheduled United States Treasury payments on time and in full for the 33rd consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $724 million, which is a decrease of approximately 39 percent from the prior fiscal year.

In Fiscal Year 2016, Federal System net revenues were $277 million, a decrease of approximately $128 million from net revenues of $405 million in Fiscal Year 2015. Bonneville reported Adjusted Net Revenues of negative $31 million for Fiscal Year 2016. In Fiscal Year 2016, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $3.3 billion, which is about the same as the prior fiscal year. Power Services' gross sales increased $3 million, or approximately 0.1 percent, in Fiscal Year 2016 compared to Fiscal Year 2015 primarily due to a $150 million increase of firm power sales revenue in Fiscal Year 2016 as compared to Fiscal Year 2015 due to the power rate increase which took effect beginning October 1, 2015. This $150 million increase was offset by: (i) an $87 million decrease in seasonal surplus (secondary) sales in Fiscal Year 2016 due to lower short-term energy market prices that Bonneville could obtain for the sale of seasonal surplus (secondary) energy and below-average hydro-generation power supply and (ii) a $60 million reduction in DSI sales at the IP Rate. January through July 2016 runoff volume at The Dalles Dam was 98 MAF. The Fiscal Year 2016 volume finished at 123 MAF, an increase of 10 MAF from the 113 MAF attained in Fiscal Year 2015, and below the historical average of 132 MAF.

Transmission Services gross sales increased $1 million in Fiscal Year 2016 compared to Fiscal Year 2015, primarily due to the transmission rate increase which took effect beginning October 1, 2015. This increase was partially offset by: (i) a one-time adjustment to increase revenues recorded in Fiscal Year 2015 for amounts that should have been paid to Bonneville for certain transmission services, (ii) milder winter and summer temperatures in 2016, and (iii) a transmission service that Bonneville ceased to provide in fiscal year 2016.

Miscellaneous transmission revenues increased $10 million over Fiscal Year 2015 primarily due to $8 million of reimbursable revenue associated with transmission work performed for Bonneville customers. Reimbursable revenues are generally offset by an equivalent amount of reimbursable expenses.

United States Treasury credits decreased $5 million for Fiscal Year 2016 from Fiscal Year 2015. The decrease was primarily due to lower replacement power purchases and capital expenditures required for fish and wildlife mitigation purposes.

Operating expense increased $145 million in Fiscal Year 2016 from Fiscal Year 2015. Operations and maintenance expense increased $66 million, or three percent, from the prior fiscal year primarily due to: (i) an increase of $80 million for energy conservation due to the transition to expense of energy conservation costs starting in Fiscal Year 2016, (ii) the absence of a one-time adjustment to reduce operating expense in the amount of $27 million in Fiscal Year 2015, (iii) a scheduled increase of $18 million in Residential Exchange Program benefits, and (iv) a decrease of $60 million in Columbia Generating Station plant costs since Fiscal Year 2016 was not a re-fueling year.

Purchased power expense, including the effects of bookouts, increased $35 million for Fiscal Year 2016 as compared to Fiscal Year 2015 primarily due to less compensation (amounts that are recorded as a reduction of purchase power expense) from certain water storage agreements with BC Hydro.

Non-Federal Debt Service increased $20 million and reflects terms of the related outstanding debt and debt management actions with respect to Regional Cooperation Debt to extend bond maturities.

Depreciation and amortization increased $23 million, or five percent, from the prior fiscal year, primarily due to increased completed plant in service for Power Services and Transmission Services construction projects.

At the end of Fiscal Year 2016, RAR for Power Services operations were $159 million, a decrease of 60 percent from the prior fiscal year, and RAR for Transmission Services operations were $444 million, a decrease of one percent from the prior fiscal year. Aggregate Bonneville RAR were $602 million, a decrease of 29 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." Any reallocation of RAR from Transmission Services to Power Services would be applied prospectively starting in Fiscal Year 2019. Bonneville does not plan to restate any prior year-end business line RAR balances. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Fiscal Year 2019 Expectations and Related Information."

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.

Statement of Non-Federal Debt Service Coverage and United States Treasury Payments (unaudited)

As of Sept. 30 – Dollars in millions	**2018**	**2017**	**2016**
Total Operating Revenues	$3,710	$3,570	$3,433
Less: Operating Expenses(1)	1,840	1,842	1,735
Net Funds Available to meet Non-Federal Debt Service Obligations	1,870	1,728	1,698
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects(2)	267	241	249
Lease-Purchase Program(3)	61	58	52
Electric Power Prepayments (4)	31	31	31
Total Non-Federal Debt Service Obligations	359	330	332
Revenue Available for Treasury	1,511	1,398	1,366
Amount Allocated for Payment to Treasury(5):			
Corps and Reclamation O&M(6)	418	416	402
Net Interest Expense(7)	207	247	298
Lease-Purchase Program(3)	(61)	(59)	(52)
Electric Power Prepayments(4)	(12)	(12)	(13)
Capitalization Adjustment(8)	65	65	65
Allowance for Funds Used During Construction (9)	11	12	17
Amortization of Federal Principal(10)	569	909	1,437
Total Amount Allocated for Payment to Treasury(5)	1,197	1,578	2,154
Non-Federal Debt Service Coverage Ratio(11)	5.2x	5.2x	5.1x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio(12)	1.7x	1.6x	1.7x

(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 2016, 2017, and 2018 respectively.

(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 as shown here is a reduction of Amount Allocated for Payment to Treasury. The aggregate debt service amount represents interest expense only.

(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 as shown 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 2018, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $31 million. Of this amount, $12 million is accounted for as Net Interest Expense and $19 million is accounted for as the repayment of principal. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments."

(5) In contrast to the "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2016, 2017, and 2018 were $1.9 billion, $1.3 billion, and $862 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."

(6) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Reclamation, and Fish and Wildlife Service for Fiscal Years 2016, 2017, and 2018. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(7) 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 (see footnotes (3) and (4)). Amounts shown are calculated on an accrual basis.

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

(9) 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.

(10) Non-Federal Debt Service Coverage Ratios increased in Fiscal Years 2014-2018 due to Non-Federal Debt management actions including Regional Cooperation Debt. Regional Cooperation Debt actions enabled Bonneville to prepay $275 million in high-interest rate Federal Appropriations Repayment Obligations in Fiscal Year 2018, $687 million in Fiscal Year 2017, and $959 million in Fiscal Year 2016, 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 "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

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

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

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

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

(The Non-Federal Debt Service plus Operating Expense Coverage Ratio increased in Fiscal Years 2014-2018 due to Non-Federal Debt management actions including Regional Cooperation Debt which enabled

Bonneville to prepay additional high-interest rate Federal Appropriations Repayment Obligations. These prepayments, and the extension of Energy Northwest debt, lowered the Non-Federal Projects Debt Service Obligations in Fiscal Years 2014-2018 resulting in atypically high Non-Federal Debt Service plus Operating Expense Coverage Ratios. In Fiscal Years 2011-2013, which immediately preceded the commencement of the Regional Cooperation Debt initiative, the Non-Federal Debt Service plus Operating Expense Coverage Ratios were 1.4x in each year. Bonneville can provide no assurance regarding future debt service coverage ratios. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.")

Management's Discussion of Unaudited Results for the Six Months ended March 31, 2019

Total operating revenues were $1.9 billion through the second quarter of Fiscal Year 2019 ("Fiscal Year 2019 Second Quarter"), a decrease of $8 million as compared to operating revenues for the six months ended March 31, 2018 ("Fiscal Year 2018 Second Quarter"). Consolidated gross sales for Power and Transmission Services, including the effect of bookouts, decreased $57 million through Fiscal Year 2019 Second Quarter compared to consolidated gross sales through Fiscal Year 2018 Second Quarter. ("Bookouts" are a reflection of accounting guidance associated with energy activities that are settled other than by the physical delivery of power and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for book-outs has no effect on net revenues, cash flows, or margins.)

Power Services gross sales decreased $33 million through Fiscal Year 2019 Second Quarter as compared to Fiscal Year 2018 Second Quarter. Firm power sales increased by $13 million primarily due to higher sales to Alcoa, who is under a contract that expires at the end of August 2019 and higher load shaping and demand revenues due to persistent cold weather during the second quarter of fiscal year 2019. Seasonal surplus (secondary) energy sales decreased $46 million primarily due to lower streamflows and water available to generate power for surplus sales. United States Treasury credits for fish and wildlife mitigation increased $28 million due to decreased streamflows through the first half of Fiscal Year 2019 Second Quarter which led to an increase in purchased power expense.

Through Fiscal Year 2019 Second Quarter, total operating expenses were $1.7 billion, a $204 million increase when compared to Fiscal Year 2018 Second Quarter. Operations and maintenance expense increased $43 million primarily due to a $54 million increase in Columbia Generating Station plant costs since Fiscal Year 2019 is a refueling year and maintenance expense is typically higher in refueling years. Purchased power expense, including the effects of bookouts, increased $186 million primarily due to contracted power purchases resulting from decreased streamflows and an expense for the value of released storage water by BC Hydro at a time of high power prices.

Non-Federal Debt Service decreased $43 million through Fiscal Year 2019 Second Quarter as compared to Fiscal Year 2018 Second Quarter, primarily due to the receipt of additional revenues by Energy Northwest for the sale of its nuclear fuel that is treated as an offset to debt service related to outstanding debt for Columbia Generating Station.

Depreciation and amortization increased $18 million through Fiscal Year 2019 Second Quarter as compared to Fiscal Year 2018 Second Quarter due to revised depreciation rates that went into effect in March 2018 which increased the utility plant assets in service.

For further information regarding Fiscal Year 2019 Second Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE SIX MONTHS ENDED MARCH 31, 2019."

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 and other plaintiffs in the Oregon Federal 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, and the 2010 Supplemental Biological Opinion, each of which attempted to correct the deficiencies identified by the court) and subsequent challenges under the ESA, the Administrative Procedures Act, the Clean Water Act, 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, National Wildlife Federation and other plaintiffs challenged NOAA Fisheries' biological opinion and the Corps' and Reclamation's decision documents in Oregon Federal District Court, and the State of Oregon intervened as a plaintiff in this litigation in October 2014. In both the Oregon Federal District Court and Ninth Circuit Court actions, plaintiffs allege that the 2014 Columbia River System Supplemental Biological Opinion and related decisions violate certain provisions of the ESA, NEPA, and Administrative Procedure Act. These lawsuits are 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 Oregon Federal 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 Oregon Federal District Court issued a ruling on the ESA challenges to the 2014 Columbia River System Supplemental Biological Opinion and the NEPA challenge. The Oregon Federal 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 "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On July 6, 2016, the Oregon Federal District Court issued an order directing that 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 Oregon Federal District Court issued an order adjusting the deadline for the new biological opinion and environmental impact statement to March 26, 2021. That date has since been accelerated by approximately one year by the *Presidential Memorandum on Promoting the Reliable Supply and Delivery of Water in the West*, issued on October 18, 2018. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," "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 Oregon Federal District Court seeking increased spring spill at eight Snake and Columbia River Federal 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 Oregon Federal 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 Oregon Federal 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 Oregon Federal District Court issued a final order directing increased spill for the spring 2018 fish passage season (approximately April-June 2018) at all eight Snake River and Columbia River Federal System dams identified in the injunction motions.

The Ninth Circuit Court issued an opinion on April 2, 2018, affirming the Oregon Federal District Court's spill and fish monitoring injunctions. Spill for fish passage under the Oregon Federal 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, plaintiffs the State of Oregon and the Nez Perce Tribe entered into an agreement in which the agencies agreed to specified spring spill operations in 2019 and 2020 in exchange for a pause in litigation on the biological opinion. The agreement sets the cost of the 2019 spring spill to Bonneville 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 incorporating the agreed to spring spill operations, effective April 1, 2019 until a new action is adopted through records of decision related to the ongoing Columbia River System Operations NEPA process. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

With respect to the capital project injunction, the Oregon Federal District Court concluded that capital spending at the four lower Snake River dams is "likely to cause irreparable harm" under NEPA by creating a significant risk of bias in the NEPA process. The Oregon Federal District Court declined, however, to enjoin the turbine runner and stator wind replacements at the Ice Harbor dam because their primary benefit is increasing fish survival. The court ordered the federal government to develop a proposal to disclose sufficient information to the plaintiffs on future capital spending projects at each dam during the NEPA remand period at appropriate and regular intervals. On May 16, 2017, the parties filed a joint proposed notification process which the Court adopted in an order dated May 25, 2017. The plaintiffs are invited to file new motions to enjoin future projects that the plaintiffs believe are not needed for safe operation of the dams and substantially may bias the NEPA process. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

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 Administrative Procedure Act. 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. Recently, 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 is due on May 10, 2019 and EPA's reply is due on June 7, 2019. The Ninth Circuit Court expects to hear oral arguments in August of 2019.

Bonneville is not a party to this suit but the complaint implies that Federal System Hydroelectric Projects on the Columbia and lower Snake River are responsible for the high water temperatures and exceedances of water quality standards. Bonneville is unable to predict the outcome of this litigation but it could lead to potential changes in the operation and configuration of the Federal System Hydroelectric Projects.

Southern California Edison v. Bonneville Power Administration

In 2004 and 2006, Southern California Edison ("SCE") filed certain claims in the United States Court of Federal Claims against Bonneville relating to actions taken by Bonneville under a 1988 power sale contract between Bonneville and SCE.

In 2006, Bonneville and SCE executed an agreement to settle the claims, whereby Bonneville agreed to make a settlement payment of $28.5 million plus interest to SCE in exchange for SCE's dismissing the two claims. On February 5, 2018, Bonneville signed a settlement agreement that resolves the FERC California Refund Docket (as hereinafter described), and filed it with FERC on February 8, 2018. In May 2018, FERC approved the settlement agreement and $41.1 million ($28.5 million plus accrued interest) was transferred to SCE from a California Power Exchange escrow account holding monies due and owing Bonneville. This litigation has ended. See "—Litigation and Related Disputes Arising from the West Coast Energy Crisis in 1999-2001."

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.

Litigation and Related Disputes Arising from the West Coast Energy Crisis in 1999-2001

In connection with the historically high power prices and volatility in West Coast power markets in 1999-2001, FERC initiated three proceedings to address, under the Federal Power Act ("FPA"), whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. The foregoing proceedings and the problems experienced in West Coast power markets in 1999-2001 have also engendered litigation affecting Bonneville.

The "FERC California Refund Docket" FERC examined, among other things, whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC examined whether and the extent to which power prices were "unjust and unreasonable." The California Power Exchange ("Cal-PX") (which filed for bankruptcy protection and has ceased operations) and the Cal-ISO operated centralized market-clearing price auction energy markets where buyers could purchase power.

Under the competitive power market structure that California established, Bonneville sold power to the Cal-ISO and the Cal-PX in 2000 and 2001. The California investor-owned utilities, which were obligated by law to purchase from the Cal-ISO and Cal-PX markets, later sought at FERC refunds for their purchases. In litigation arising out of the FERC California Refund Docket, the Ninth Circuit Court ultimately held, in September 2005, that Bonneville was not (under law in effect at the time) subject to FERC authority to order refunds (the "September 2005 Ninth Circuit Court Opinion"). As a result of the court's ruling, the FERC California Refund Docket did not in and of itself result in any FERC-ordered refund liability for Bonneville. Notwithstanding the September 2005 Ninth Circuit Court Opinion, Bonneville remained a party to the FERC California Refund Docket.

On April 25, 2012, Bonneville received $74 million from the Cal-ISO and Cal-PX for the principal amount of withheld outstanding payment obligations to Bonneville for sales during the period (2000-2001) at issue in the case. Under a FERC order, the accrued interest through April 25, 2012 did not become payable until the FERC California Refund Docket was finally resolved.

In light of the September 2005 Ninth Circuit Court Opinion, the California Attorney General on behalf of California Energy Scheduling Resources, which is a California state agency, and three California-based investor-owned utilities (Pacific Gas and Electric ("PG&E"), San Diego Gas and Electric, and Southern California Edison ("SCE"), (the foregoing four parties are referred to collectively herein as the "California Parties"), filed separate breach of contract claims against Bonneville in the United States Court of Federal Claims ("Court of Federal Claims") in March 2007. Each claim sought unspecified damages related to Bonneville's power sales and related transactions into the Cal-PX and Cal-ISO markets (the "California Breach Claims"). The California Parties' claims in the California Breach Claims litigation were predicated on the assertion that in its transactions into the Cal-PX and Cal-ISO markets, Bonneville had agreed by contract to accept prices by reference to tariff rates.

On February 5, 2018, Bonneville signed a settlement agreement to resolve the FERC California Refund Docket and filed it with FERC on February 8, 2018. The settlement agreement provided for: (i) the transfer of $41.1 million to SCE to resolve the Southern California Edison v. Bonneville Power Administration litigation (see "—Southern California Edison v. Bonneville Power Administration"), (ii) $16.3 million to Bonneville for interest income from the Cal-ISO and Cal-PX, and (iii) $457,441 to certain market participants. These amounts were paid from a California Power Exchange escrow account holding monies due and owing Bonneville and others in the market. In May 2018, FERC approved the settlement and the litigation concerning the FERC California Refund Docket has ended.

Hourly Southern Intertie Transmission Rate Challenge

In November 2017, a small group of public agencies in the State of California filed petitions challenging FERC's interim approval of one of the transmission rates in the 2018-2019 Final Rate Proposal. In particular, the petitioners challenged Bonneville's transmission rates related to hourly transmission service on the Southern Intertie. The Southern Intertie consists of transmission lines and facilities that are used to transfer electric power between the Pacific Northwest and California. Only one of the petitioners is a Bonneville transmission customer that purchases this type of transmission service. The public agencies filed petitions in two courts: (i) the United States District Court of the Eastern District of California, and (ii) the Ninth Circuit Court. Bonneville was not a named party in either proceeding, but intervened in both actions. Once FERC issued a final order on the 2018-2019 Final Rate Proposal, the petitioners dismissed both petitions and filed a new petition in the Ninth Circuit Court challenging FERC's final approval of the transmission rate in the 2018-2019 Final Rate Proposal. The petitioners and Bonneville have filed briefs in the Ninth Circuit Court proceeding and oral argument is scheduled to be held on June 7, 2019. In previous years, hourly transmission service on the Southern Intertie has involved the recovery of approximately $4 million per year, in aggregate, of the costs to Bonneville of providing service on the Southern Intertie. The Final 2018-2019 Rates increase the Southern Intertie costs to be recovered under the rates for hourly Southern Intertie transmission service by approximately $2 million per year (to approximately $6 million per year in Fiscal Year 2018 and Fiscal Year 2019) to more fairly allocate costs between long-term and hourly transmission service. If the petitioners were to prevail on their challenge, it is possible that Bonneville could be required to reformulate the challenged rate.

As part of the 2020-2021 Initial Rate Proposal, Bonneville has proposed to continue a similar hourly southern intertie transmission rate as the rate included in the 2018-2019 Final Rates. The group of public agencies has opposed the settlement of the transmission rates in the 2020-2021 Initial Rate Proposal. Typically, upon final FERC review, the rates may be challenged in the Ninth Circuit Court, which has original jurisdiction over many Bonneville actions. Bonneville expects that a similar challenge to the 2020-2021 Final Rates would likely be filed once FERC has issued a final order on Bonneville's 2020-2021 Final Rate Proposal. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Year 2020-2021."

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

We have audited the accompanying combined financial statements of the Federal Columbia River Power System (FCRPS) which comprise the combined balance sheets as of September 30, 2018 and 2017 and the related combined statements of revenues and expenses and of cash flows for each of the three years in the period ended September 30, 2018.

Management's Responsibility 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; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

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

Opinion

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the financial position of the Federal Columbia River Power System as of September 30, 2018 and 2017, and the related combined statements of revenues and expenses and of cash flows for each of the three years in the period ended September 30, 2018 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 30, 2018

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

(Millions of Dollars)

	2018	2017
Assets		
Utility plant		
Completed plant	**$ 19,307.4**	$ 18,820.2
Accumulated depreciation	**(6,883.4)**	(6,588.1)
Net completed plant	**12,424.0**	12,232.1
Construction work in progress	**1,290.1**	1,193.7
Net utility plant	**13,714.1**	13,425.8
Nonfederal generation	**3,350.9**	3,518.7
Current assets		
Cash and cash equivalents	**804.2**	597.9
Short-term investments in U.S. Treasury securities	**40.2**	30.1
Accounts receivable, net of allowance	**75.2**	48.5
Accrued unbilled revenues	**292.4**	297.2
Materials and supplies, at average cost	**109.1**	112.0
Prepaid expenses	**48.2**	55.1
Total current assets	**1,369.3**	1,140.8
Other assets		
Regulatory assets	**5,587.7**	5,961.1
Nonfederal nuclear decommissioning trusts	**377.6**	346.9
Deferred charges and other	**176.8**	278.3
Total other assets	**6,142.1**	6,586.3
Total assets	**$ 24,576.4**	$ 24,671.6

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

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

(Millions of Dollars)

		2018		2017
Capitalization and Liabilities				
Capitalization and long-term liabilities				
Accumulated net revenues	**$**	**4,123.8**	$	3,680.4
Debt				
Federal appropriations		**1,791.7**		2,029.4
Borrowings from U.S. Treasury		**4,955.7**		4,918.6
Nonfederal debt		**7,111.4**		6,871.4
Total capitalization and long-term liabilities		**17,982.6**		17,499.8
Commitments and contingencies (Note 13)				
Current liabilities				
Debt				
Borrowings from U.S. Treasury		**574.9**		90.1
Nonfederal debt		**598.3**		1,390.9
Accounts payable and other		**511.4**		517.4
Total current liabilities		**1,684.6**		1,998.4
Other liabilities				
Regulatory liabilities		**1,912.0**		2,047.0
IOU exchange benefits		**2,256.7**		2,415.7
Asset retirement obligations		**208.0**		191.7
Deferred credits and other		**532.5**		519.0
Total other liabilities		**4,909.2**		5,173.4
Total capitalization and liabilities	**$**	**24,576.4**	$	24,671.6

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

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

(Millions of Dollars)

	2018	2017	2016
Operating revenues			
Sales	**$ 3,560.5**	$ 3,440.5	$ 3,283.5
U.S. Treasury credits	**74.7**	58.3	77.2
Miscellaneous revenues	**75.1**	71.0	71.9
Total operating revenues	**3,710.3**	3,569.8	3,432.6
Operating expenses			
Operations and maintenance	**2,098.7**	2,110.7	2,025.3
Purchased power	**159.5**	147.4	111.7
Nonfederal projects	**266.9**	241.3	249.2
Depreciation and amortization	**507.3**	485.0	471.1
Total operating expenses	**3,032.4**	2,984.4	2,857.3
Net operating revenues	**677.9**	585.4	575.3
Interest expense and (income)			
Interest expense	**245.1**	285.9	353.8
Allowance for funds used during construction	**(31.5)**	(33.0)	(40.3)
Interest income	**(6.3)**	(6.1)	(15.4)
Net interest expense	**207.3**	246.8	298.1
Net revenues	**470.6**	338.6	277.2
Accumulated net revenues, beginning of year	**3,680.4**	3,392.6	3,175.7
Irrigation assistance	**(27.2)**	(50.8)	(60.3)
Accumulated net revenues, end of year	**$ 4,123.8**	$ 3,680.4	$ 3,392.6

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

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

	2018	2017	2016
Cash flows from operating activities			
Net revenues	**$ 470.6**	$ 338.6	$ 277.2
Adjustments to reconcile net revenues to cash provided by operations:			
Depreciation and amortization	**507.3**	485.0	471.1
Amortization of nonfederal projects	**199.5**	67.2	25.9
Deferred payments for Energy Northwest-related O&M and interest	**141.0**	458.3	259.0
Changes in:			
Receivables and unbilled revenues	**(21.9)**	(13.4)	8.3
Materials and supplies	**2.9**	(0.1)	5.0
Prepaid expenses	**6.9**	(33.2)	(4.4)
Accounts payable and other	**7.2**	71.3	(92.5)
Regulatory assets and liabilities	**50.8**	92.3	65.0
IOU exchange benefits	**(159.0)**	(136.2)	(132.0)
Other assets and liabilities	**(3.5)**	(50.9)	(27.8)
Net cash provided by operating activities	**1,201.8**	1,278.9	854.8
Cash flows from investing activities			
Investment in utility plant, including AFUDC	**(703.7)**	(692.0)	(808.3)
U.S. Treasury securities:			
Purchases	**(332.1)**	(1,109.0)	(939.0)
Maturities	**322.0**	1,352.3	1,356.9
Deposits to nonfederal nuclear decommissioning trusts	**(3.8)**	(3.6)	(3.5)
Lease-purchase trust funds:			
Deposits to	**(9.6)**	(103.8)	(90.6)
Receipts from	**58.9**	132.4	219.1
Net cash used for investing activities	**(668.3)**	(423.7)	(265.4)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	**44.2**	71.2	83.0
Repayment	**(281.9)**	(908.7)	(1,117.8)
Borrowings from U.S. Treasury:			
Proceeds	**809.0**	250.0	429.0
Repayment	**(287.1)**	-	(319.0)
Nonfederal debt:			
Proceeds	**30.6**	104.1	411.6
Repayment	**(677.5)**	(293.1)	(49.6)
Customers:			
Net advances for construction	**80.5**	21.7	5.1
Repayment of funds used for construction	**(17.8)**	(31.3)	(38.5)
Irrigation assistance	**(27.2)**	(50.8)	(60.3)
Net cash used for financing activities	**(327.2)**	(836.9)	(656.5)
Net increase (decrease) in cash and cash equivalents	**206.3**	18.3	(67.1)
Cash and cash equivalents at beginning of year	**597.9**	579.6	646.7
Cash and cash equivalents at end of year	**$ 804.2**	$ 597.9	$ 579.6
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 275.7**	$ 316.1	$ 376.2
Significant noncash investing and financing activities:			
Nonfederal debt increase for Energy Northwest	**$ 1,257.4**	$ 1,046.2	$ 320.7
Nonfederal debt decrease for Energy Northwest	**$ (1,163.5)**	$ (601.5)	$ (217.9)
Other nonfederal	**$ 0.4**	$ (9.2)	$ 11.6

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

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination and consolidation 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 7, Debt and Appropriations, and Note 8, 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) applicable to federal entities 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 proposed 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.

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 4, 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 2, Utility Plant.)

Depreciation and amortization

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 2, Utility Plant.)

In the event removal costs 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 4, Effects of Regulation.)

Amortization expense relates to certain regulatory assets. (See Note 4, Effects of Regulation.)

Allowance for funds used during construction

AFUDC represents the estimated cost of interest on financing the construction of new assets. AFUDC is based on the construction work in progress balance and is charged to the capitalized cost of the utility plant asset. AFUDC 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 2, Utility Plant.) 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 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 Columbia Generating Station (CGS) nuclear power plant and, through June 2032, Lewis County PUD's Cowlitz Falls Hydroelectric Project. These contracts require BPA to meet all of the facilities' operating, maintenance and debt service costs. Operations and maintenance and debt service expenses for these projects are recognized based upon annual total project cash funding requirements, which vary from year to year. The Nonfederal generation assets on the Combined Balance Sheets are amortized over the term of the related outstanding nonfederal debt, with the amortization expense included in Nonfederal projects in the Combined Statements of Revenues and Expenses. (See Note 7, Debt and Appropriations.)

Cash and cash equivalents

Cash amounts for the FCRPS include cash 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. The Bonneville Fund also includes cash equivalents, which consist of investments in non-marketable market-based special securities issued by the U.S. Treasury (market-based specials) with maturities of 90 days or less at the date of investment. The carrying value of cash and cash equivalents approximates fair value.

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 2018, 2017 and 2016, 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 11, Risk Management and Derivative Instruments.)

Allowance for doubtful accounts

Management reviews accounts receivable to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific customer accounts, based upon the best available facts and circumstances of customers that may be unable to meet their financial obligations, and a reserve for all other customers based on historical experience. The balance 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 are generally 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 capacity. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts settle. (See Note 11, Risk Management and Derivative Instruments.)

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. The FCRPS does not apply hedge accounting.

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 11, Risk Management and Derivative Instruments and Note 12, Fair Value Measurements.)

Revenues and net revenues

Operating revenues are recorded when power, transmission and related services are delivered and include estimated unbilled revenues. 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. 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 Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). This Act requires BPA to recover the nonpower portion of expenditures 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.

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.

Nonfederal projects

Nonfederal projects expense represents the amortization of nonfederal generation assets and regulatory assets for terminated nonfederal nuclear and hydro facilities, as well as the interest expense on the debt related to those assets. This expense varies from year to year and is recognized over the terms of the related outstanding debt, which reflect refinancing actions, if any, undertaken during the fiscal year.

Interest expense

Interest expense includes interest associated with the unpaid balance of federal appropriations scheduled for repayment, interest on bonds issued by BPA to the U.S. Treasury and interest on certain nonfederal debt and liabilities. Reductions to interest expense include the amortization of a capitalization adjustment regulatory liability. (See Note 4, Effects of Regulation.) Interest expense excludes interest on nonfederal debt related to operating or terminated generation assets that is instead reported as a component of nonfederal projects expense. (See Note 7, Debt and Appropriations.)

Interest income

Interest income includes interest earnings on market-based special securities in the Bonneville Fund and interest earnings from other sources. The U.S. Treasury provides investment services to federal government entities such as BPA that have funds on deposit with the U.S. Treasury and have legislative authority to invest those funds. Investments of the funds are generally restricted to special non-marketable securities, also called market-based specials. Interest earnings on U.S. Treasury market-based special investments are based on the stated rates of the individual securities. Beginning with fiscal year 2017, BPA ceased earning interest offset credits on balances in the Bonneville Fund. Through Sept. 30, 2016, however, BPA earned interest offset credits on certain cash balances in the Bonneville Fund that were not invested in market-based specials. These credits reduced some interest payments, associated with federally appropriated investments in the FCRPS, in the amount of the interest earned. The interest offset credits were earned at the weighted-average interest rate of BPA's outstanding U.S. Treasury borrowings. (See Note 3, Investments in U.S. Treasury Securities.)

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 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 provides for fixed "Scheduled Amounts" payable to the IOUs, as well as fixed "Refund Amounts" payable to the COUs. The Refund Amounts do not reduce rates but are bill credits to qualifying COUs as designated in the 2012 REP Settlement Agreement. (See Note 9, 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 Employee 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.

RECENT ACCOUNTING PRONOUNCEMENTS

Revenue from contracts with customers

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) on revenue from contracts with customers that supersedes the existing revenue recognition guidance, including most industry-specific guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within and across industries. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to Accumulated net revenues on the Combined Balance Sheets for initial application of the guidance at the date of initial adoption (modified retrospective method).

Management adopted this standard on Oct. 1, 2018, using a modified retrospective method, with no adjustment to the opening Accumulated net revenues on the Combined Balance Sheets.

The adoption of this guidance will not have a material impact on either the timing or amount of revenues recognized. Management anticipates additional disclosures around the nature, amount, timing and uncertainty of FCRPS revenues and cash flows arising from contracts with customers. These additional disclosures will include the disaggregation of revenues by product.

Financial instruments, recognition and measurement

In January 2016, the FASB issued an ASU to address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. The ASU supersedes existing guidance to classify equity securities as trading or available-for-sale and requires all equity securities to be measured at fair value with changes in fair value recognized through net revenues. In addition, the ASU exempts all entities that are not public business entities from disclosing fair value information for financial instruments measured at amortized cost. Management is evaluating the impact of adopting this guidance, which will be effective in fiscal year 2020.

Leases

In February 2016, the FASB issued an ASU on leases. The primary change under the ASU is the recognition of lease assets and corresponding lease liabilities by lessees for those agreements currently classified as operating leases, which currently are not recognized on the balance sheet. In addition, the guidance requires both quantitative and qualitative disclosures regarding amounts recognized in the financial statements and significant judgments made by management in applying the lease standard. Management anticipates an increase in assets and liabilities and expanded financial disclosure as a result of the guidance. However, the magnitude of change to specific financial statement line items and the impact to financial statement presentation continue to be under evaluation. This guidance will be effective in fiscal year 2020.

Classification of certain cash receipts and cash payments in the statement of cash flows

In August 2016, the FASB issued an ASU to address eight specific cash flow issues with the objective of reducing the existing diversity in practice. Management is evaluating the impact of adopting this guidance, which will be effective in fiscal year 2020.

Restricted cash

In November 2016, the FASB issued an ASU to address the classification and presentation of changes in restricted cash on the statement of cash flows with the objective of reducing the existing diversity in practice. Management is evaluating the impact of adopting this guidance, which will be effective in fiscal year 2020.

Financial instruments, credit losses

In June 2016, the FASB issued an ASU to amend guidance related to credit losses on financial instruments held by a reporting entity. Instead of recognizing credit losses when such losses are probable, the ASU requires assets measured at amortized cost to be presented at the net amount expected to be collected. In addition, credit losses relating to available-for-sale debt securities are required to be recorded through an allowance for credit losses. Management is evaluating the impact of adopting this guidance, which will be effective in fiscal year 2022.

SUBSEQUENT EVENTS

Management has performed an evaluation of events and transactions for potential FCRPS recognition or disclosure through Oct. 30, 2018, which is the date the financial statements were issued.

In October 2018, certain agreements were signed to extend the existing Columbia Basin Fish Accords to the period between October 2018 and Sept. 30, 2022, at the latest. (See Note 13, Commitments and Contingencies.)

2. Utility Plant

As of Sept. 30 — millions of dollars	2018	2017	2018 Estimated average service lives
Completed plant			
Federal system hydro generation assets	$ 9,280.7	$ 9,109.2	75 years
Transmission assets	9,869.3	9,525.8	51 years
Other assets	157.4	185.2	7 years
Completed plant	$ 19,307.4	$ 18,820.2	
Accumulated depreciation			
Federal system hydro generation assets	$ (3,485.1)	$ (3,355.4)	
Transmission assets	(3,319.6)	(3,138.5)	
Other assets	(78.7)	(94.2)	
Accumulated depreciation	$ (6,883.4)	$ (6,588.1)	
Construction work in progress			
Federal system hydro generation assets	$ 668.7	$ 567.5	
Transmission assets	602.1	606.2	
Other assets	19.3	20.0	
Construction work in progress	$ 1,290.1	$ 1,193.7	
Net Utility Plant	$ 13,714.1	$ 13,425.8	

Allowance for funds used during construction

Fiscal year	2018	2017	2016
BPA rate	3.1%	3.1%	3.0%
Appropriated rate	1.3%	0.6%	0.4%

Completed plant assets include transmission capital leased assets of $1.88 billion and $1.71 billion, with accumulated depreciation of $141.0 million and $93.8 million, at Sept. 30, 2018, and 2017, respectively.

In fiscal year 2018, BPA completed a depreciation study on BPA's transmission and general plant assets. As a result of the study, the average service lives for transmission assets have increased from 48 years to 51 years. However, when also considering changes to net salvage estimates, which include cost of removal and salvage proceeds, depreciation expense increased approximately $19 million in fiscal year 2018. Beginning with fiscal year 2019, results of the depreciation study will increase depreciation expense by approximately $34 million per year.

On May 18, 2017, BPA announced the decision to terminate the I-5 Corridor Reinforcement Project, a proposed 80-mile, 500-kilovolt transmission line that would have stretched from Castle Rock, Washington to Troutdale, Oregon. Cumulative capitalized costs associated with this project of $130.0 million were reclassified in fiscal year 2017 from Construction work in progress to a Regulatory asset on the Combined Balance Sheets, as these costs are expected to be recovered through future rates. (See Note 4, Effects of Regulation.)

3. Investments in U.S. Treasury Securities

As of Sept. 30 — millions of dollars	2018		2017	
	Amortized cost	Fair value	Amortized cost	Fair value
Short-term	$ 40.2	$ 40.2	$ 30.1	$ 30.1

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. Beginning on Oct. 1, 2016, all balances in the Bonneville Fund were invested through the Federal Investment Program, and BPA ceased earning interest offset credits as it did during prior years. Instead, for cash and cash equivalents in the Bonneville Fund, BPA only earns interest on cash balances it invests in market-based specials.

Market-based specials held during fiscal years 2018 and 2017 had maturities of up to one year. These securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity. The amounts shown in the preceding table exclude U.S. Treasury securities with maturities of 90 days or less at the date of investment, which are considered cash equivalents and are included on the Combined Balance Sheets as part of Cash and cash equivalents. The fair value measurements of investments in U.S. Treasury securities are considered Level 2 in the fair value hierarchy as defined by the accounting guidance for fair value measurements and disclosures. (See Note 12, Fair Value Measurements.)

4. Effects of Regulation

REGULATORY ASSETS

As of Sept. 30 — millions of dollars	2018	2017
IOU exchange benefits	$ 2,256.7	$ 2,415.7
Terminated nuclear facilities	1,709.0	1,786.3
Columbia River Fish Mitigation	755.0	741.0
Fish and wildlife measures	254.2	255.9
Conservation measures	249.6	291.7
Terminated I-5 Corridor Reinforcement Project	130.0	130.0
REP Refund Amounts	75.7	150.0
Spacer damper replacement program	44.9	46.5
Trojan decommissioning and site restoration	38.0	26.9
Federal Employees' Compensation Act	27.0	29.6
Legal claims and settlements	23.0	57.6
Terminated hydro facilities	10.2	11.6
Derivative instruments	7.3	10.7
Other	7.1	7.6
Total	$ 5,587.7	$ 5,961.1

Regulatory assets include the following items:

"**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 9, 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 nonfederal projects expense over the term of the related outstanding debt. (See Note 7, Debt and Appropriations.)

"**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. These costs are recovered in rates over 75 years and amortized to depreciation and amortization expense.

"**Fish and wildlife measures**" consist of deferred fish and wildlife project expenses to be recovered in future rates. These costs are amortized to depreciation and amortization expense over a period of 15 years.

"**Conservation measures**" consist of the costs of deferred energy conservation measures to be recovered in future rates. These costs are amortized to depreciation and amortization 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 and the BP-16 rate period, began expensing such costs as incurred.

"Terminated I-5 Corridor Reinforcement Project" consists of the costs to be recovered in future rates for preliminary construction and related activities for the I-5 Corridor Reinforcement Project. In May 2017, BPA terminated this construction project. These costs were reclassified from Construction work in progress to a Regulatory asset on the Combined Balance Sheets, as such costs are expected to be recovered through future rates. BPA expects that these costs will be amortized to depreciation and amortization expense beginning in fiscal year 2020. The amortization period will be determined prior to the BP-20 rate proposal, which is likely to conclude in fiscal year 2019.

"**REP Refund Amounts**" are amounts that were established in the 2012 REP Settlement Agreement. (See Note 9, Residential Exchange Program.) These amounts are recovered in rates through 2019 from IOUs as a reduction in their IOU Exchange benefits and are equal to the regulatory liability for REP Refund Amounts to COUs.

"**Spacer damper replacement program**" consists of costs to replace deteriorated spacer dampers and are recovered in future rates under the Spacer Damper Replacement Program. These costs are amortized to depreciation and amortization expense over a period of 25 or 30 years.

"**Trojan decommissioning and site restoration**" reflects the amount to be recovered in future rates for funding the asset retirement obligation (ARO) liability related to the former Trojan nuclear facility. This amount equals the associated liability. (See Note 5, Asset Retirement Obligations.)

"**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 6, Deferred Charges and Other.)

"**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 established by BPA. The balance as of Sept. 30, 2018, also reflects a decrease of $35.3 million for the California refund settlement that occurred during fiscal year 2018. (See Note 13, Commitments and Contingencies.)

"**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 nonfederal projects expense over the term of the related outstanding debt. (See Note 7, Debt and Appropriations.)

"**Derivative instruments**" reflect the unrealized losses from BPA's derivative portfolio. These amounts are deferred over the corresponding underlying contract delivery months. (See Note 11, Risk Management and Derivative Instruments.)

REGULATORY LIABILITIES

As of Sept. 30 — millions of dollars	2018	2017
Capitalization adjustment	$ 1,147.5	$ 1,212.4
Accumulated plant removal costs	455.5	434.3
Decommissioning and site restoration	210.2	184.7
REP Refund Amounts to COUs	75.7	150.0
Derivative instruments	16.6	59.2
Other	6.5	6.4
Total	$ 1,912.0	$ 2,047.0

Regulatory liabilities include the following items:

"**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 (Refinancing Act), 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 2018, 2017 and 2016.

"**Accumulated plant removal costs**" are the amounts previously collected through rates as part of depreciation expense. The liability will be reduced as actual removal costs are incurred. (See Note 1, Summary of Significant Accounting Policies.)

"**Decommissioning and site restoration**" is the amount previously collected through rates and invested in the related nonfederal nuclear decommissioning trusts in excess of the ARO balances for (i) CGS decommissioning and site restoration, and (ii) Energy Northwest Projects 1 and 4 site restoration. (See Note 5, Asset Retirement Obligations.)

"**REP Refund Amounts to COUs**" are the amounts previously collected through rates that are owed to qualifying COUs and will be provided as future bill credits through fiscal year 2019 as established in the 2012 REP Settlement Agreement. These amounts are equal to regulatory assets for REP Refund Amounts. (See Note 9, Residential Exchange Program.)

"**Derivative instruments**" reflect the unrealized gains from BPA's derivative portfolio. These amounts are deferred over the corresponding underlying contract delivery months. (See Note 11, Risk Management and Derivative Instruments.)

5. Asset Retirement Obligations

As of Sept. 30 — millions of dollars	2018	2017
Beginning Balance	$ 191.7	$ 185.7
Activities:		
Accretion	9.9	9.4
Expenditures	(2.8)	(3.9)
Revisions	9.2	0.5
Ending Balance	$ 208.0	$ 191.7

AROs are recognized based on the estimated fair value of the dismantlement and restoration costs associated with the retirement of certain tangible long-lived assets. The liability is adjusted for any revisions, expenditures and the passage of time. The FCRPS also has tangible long-lived assets such as federal hydro projects and transmission assets without an associated ARO because no obligation exists to remove these assets.

As of Sept. 30 — millions of dollars	2018	2017
CGS decommissioning and site restoration	$ 165.9	$ 157.8
Trojan decommissioning	38.0	26.9
Energy Northwest Projects 1 and 4 site restoration	4.1	7.0
Total	$ 208.0	$ 191.7

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — millions of dollars	2018		2017	
	Amortized cost	Fair value	Amortized cost	Fair value
Equity index funds	$ 215.7	$ 280.0	$ 217.5	$ 266.3
Bond index funds	52.6	50.7	61.4	60.9
U.S. government obligation mutual funds	18.4	16.7	21.0	19.7
Cash and cash equivalents	30.2	30.2	—	—
Total	$ 316.9	$ 377.6	$ 299.9	$ 346.9

These assets represent trust fund account balances for decommissioning and site restoration costs. External trust fund accounts for decommissioning and site restoration costs for CGS are funded monthly and are charged to operations and maintenance expense. The decommissioning trust fund account was established to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (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 an NRC decommissioning cost estimate and the 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.

The investment securities in the decommissioning and site restoration trust fund accounts are classified as available-for-sale and recorded at fair value in accordance with accounting guidance for investments, debt and equity securities. Net unrealized and realized gains and losses on these investment securities are recognized as adjustments to the related regulatory liability, which represents the excess of the amount previously collected through rates over the current ARO balance. (See Note 4, Effects of Regulation.)

Contribution payments to the CGS trust fund accounts for fiscal years 2018, 2017 and 2016 were $3.8 million, $3.6 million and $3.5 million, respectively. BPA and Energy Northwest have no obligation to make further payments into the site restoration fund for Energy Northwest Projects 1 and 4.

Based on an agreement in place, BPA directly funds Eugene Water and Electric Board's 30 percent share of Trojan's decommissioning costs through current rates. Decommissioning costs are included in Operations and maintenance in the Combined Statements of Revenues and Expenses.

6. Deferred Charges and Other

As of Sept. 30 — millions of dollars	2018	2017
Lease-Purchase trust funds	$ 116.2	$ 165.1
Funding agreements	21.5	20.8
Derivative instruments	16.6	59.2
Spectrum Relocation Fund	12.2	12.8
Other	10.3	4.4
Settlements receivable	—	16.0
Total	$ 176.8	$ 278.3

Deferred Charges and Other include the following items:

"**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 7, 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.

Investments classified as trading were $95.5 million and $144.5 million, and those classified as held to maturity were $19.6 million and $19.7 million, at Sept. 30, 2018, and 2017, respectively. Trading investments are held for construction purposes and are stated at fair value based on quoted market prices. (See Note 12, Fair Value Measurements.) As of Sept. 30, 2018, and 2017, trust balances also included cash and cash equivalents of $1.1 million and $0.9 million, respectively.

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

"**Derivative instruments**" represent unrealized gains from BPA's derivative portfolio, which includes physical power purchase and sale transactions.

"**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 in the Bonneville Fund for the sole purpose of constructing replacement assets.

7. Debt and Appropriations

As of Sept. 30 — millions of dollars		2018		2017	
	Terms	Carrying Value	Weighted-Average Interest Rate	Carrying Value	Weighted-Average Interest Rate
Nonfederal debt					
Nonfederal generation:					
Columbia Generating Station	1.7 – 6.8% through 2044	$ 3,468.5	4.3%	$ 3,853.6	3.9%
Cowlitz Falls Hydro Project	4.0 – 5.3% through 2032	72.1	5.1	75.6	5.1
Terminated nonfederal generation:					
Nuclear Project 1	1.7 – 5.0% through 2028	795.6	4.9	838.5	4.8
Nuclear Project 3	1.7 – 5.0% through 2028	914.1	5.0	1,044.2	4.8
Northern Wasco Hydro Project	2.2 – 5.0% through 2024	11.4	4.2	12.8	3.9
Lease-Purchase Program:					
Capital lease obligations	1.5 – 6.1% through 2042	2,022.4	2.7	2,012.3	2.7
NIFC debt	5.5% through 2034	118.8	5.5	118.8	5.4
Other capital lease obligations	3.4 – 7.4% through 2043	37.5	5.0	39.4	5.0
Other financial liability	5.6% (not yet scheduled)	21.2	5.6	—	—
Customer prepaid power purchases	4.3 – 4.6% through 2028	248.1	4.5	267.1	4.5
Total Nonfederal debt		$ 7,709.7	4.1%	$ 8,262.3	3.8%
Federal debt and appropriations					
Borrowings from U.S. Treasury	1.1 – 5.9% through 2048	$ 5,530.6	3.2%	$ 5,008.7	3.2%
Federal appropriations	2.4 – 7.2% through 2068	1,354.6	3.9	1,583.5	4.1
Federal appropriations (not scheduled for repayment)		437.1	n/a	445.9	n/a
Total Federal debt and appropriations		$ 7,322.3	3.4%	$ 7,038.1	3.4%
Total debt and appropriations		$ 15,032.0	3.7%	$ 15,300.4	3.7%

Nonfederal generation and Terminated nonfederal generation

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. These contracts require that BPA meet all of the operating, maintenance and debt service costs for these projects. 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.

BPA recognizes expenses for these nonfederal generation and terminated nonfederal generation projects based on annual total project cash funding requirements, which include debt service and operating and maintenance expense. BPA recognized operating and maintenance expense for these projects of $272.5 million, $322.3 million and $263.2 million in fiscal years 2018, 2017 and 2016, respectively, which is included in Operations and maintenance in the Combined Statements of Revenues and Expenses. Debt service expense for all projects of $266.9 million, $241.3 million and $249.2 million for fiscal years 2018, 2017 and 2016, respectively, is reported as Nonfederal projects in the Combined Statements of Revenues and Expenses. On the Combined Balance Sheets, related assets for operating projects are included in Nonfederal generation. Related assets for terminated generation are included in Regulatory assets. (See Note 4, Effects of Regulation.)

As a result of debt management actions taken by Energy Northwest under a Regional Cooperation Debt effort with BPA, amounts otherwise collected in BPA's power and transmission rates during fiscal years 2018 and 2017 were not used to fund the Energy Northwest-related principal payments as originally scheduled, and as included in rates. Instead, these principal amounts were refinanced to fiscal year 2035 at the latest. Because of these debt management actions and the borrowings by Energy Northwest described below, BPA was able to prepay comparatively higher-interest-rate federal appropriations during fiscal years 2018 and 2017.

Energy Northwest debt of $2.26 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2019 and July 2028 at 100 percent of the principal amount.

Borrowings by Energy Northwest for expense-related purposes

As of Sept. 30 — millions of dollars	2018	2017
Amounts outstanding[1]	$ 141.0	$ 458.3
Approximate variable interest rate	2.4%	1.6%

[1] Amounts outstanding at September 30 of each fiscal year are included in the applicable nonfederal debt amounts shown in the table at the beginning of Note 7, Debt and Appropriations.

During fiscal years 2018 and 2017, Energy Northwest funded operations and maintenance for CGS and interest payments on certain bonds with line-of-credit borrowing arrangements from banking institutions. Fiscal year 2018 interest payments funded with these arrangements relates to CGS. Fiscal year 2017 interest payments relate to CGS and terminated nuclear Projects 1 and 3. These arrangements were due to be repaid on or before June 30, 2019, and June 30, 2018, respectively. In fiscal year 2018, BPA funded the repayment of $458.3 million that Energy Northwest borrowed under its fiscal year 2017 borrowing arrangement.

Energy Northwest-related expenses recorded in the FCRPS Combined Statements of Revenues and Expenses were not affected by the foregoing borrowing arrangements. Instead of providing funds to Energy Northwest for operations and maintenance and interest payment purposes, BPA will fund the repayment of the borrowing arrangements.

Lease-Purchase Program and Other capital lease obligations

Under the Lease-Purchase Program, BPA has incurred capital lease obligations 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 capital lease obligations are paid from the rental payments made by BPA. The facilities themselves 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 8, Variable Interest Entities.)

Under the Lease-Purchase Program, BPA consolidates one special purpose corporation, referred to as Northwest Infrastructure Financing Corporation (NIFC). As of Sept. 30, 2018, the NIFC had $119.6 million of bonds outstanding, including debt issuance costs. The lease rental payments from BPA are pledged to the payment of the debt, but the facilities themselves 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.

In fiscal year 2017, NIFC VI, which BPA previously consolidated, sold its lease receivables, rights to future lease revenues and title to its leased assets to the IERA. As a result, the $200.0 million NIFC VI bank line of credit was extinguished, and the new arrangement was reported as a capital lease obligation of $200.8 million instead of as NIFC debt. This transaction resulted in significant other nonfederal noncash activities on the Combined Statements of Cash Flows of $1.5 million for fiscal years 2017. This transaction also resulted in an increase of $207.4 million to transmission capital leased assets in fiscal year 2017 with an immaterial net change to Completed plant on the Combined Balance Sheets. (See Note 2, Utility Plant.)

On the Combined Balance Sheets, capital lease obligations 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. The capital lease obligations expire on various dates through 2043.

Completed plant assets reported as transmission capital leased assets are described in Note 2, Utility Plant.

Other financial liability

In June 2018, BPA entered into agreements with a transmission customer for the construction, ownership, operation and maintenance of a transmission project in Idaho, for which the customer has begun construction. BPA is the accounting owner of the assets during construction. This project includes a substation and transmission lines and is expected to be under construction by the customer until fiscal year 2020, at the earliest. Upon completion and energization, BPA is required to lease the entire capacity of the transmission facilities from the customer. As of Sept. 30, 2018, BPA recognized $21.2 million in both construction work in progress and nonfederal debt related to this project. Per terms of the agreements, BPA's total liability for these facilities will be limited to approximately $65 million. BPA's lease payments to the customer will begin upon energization of the transmission facilities and will continue for 40 years.

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 $340.0 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 percent. The prepaid liability is reduced and the credits are applied as power is delivered through fiscal year 2028.

Borrowings from U.S. Treasury

BPA is authorized by Congress to issue and sell bonds to the U.S. Treasury, and have outstanding at any one time, up to $7.70 billion aggregate principal amount of bonds. Of the $7.70 billion in U.S. Treasury borrowing authority, $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 $6.45 billion is available for BPA's transmission capital program and to implement BPA's authorities under the Northwest Power Act. Of the $7.70 billion, $750.0 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, 2018, and 2017, no bonds outstanding related to Northwest Power Act expenses.

As of Sept. 30, 2018, $1.46 billion of variable-rate bonds are callable by BPA at par value on their interest repricing dates, which occurs every six months. The remaining $4.07 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, 2017, $800.0 million of variable-rate bonds were outstanding.

In fiscal year 2018, BPA called $98.0 million of bonds it had previously issued to the U.S. Treasury. As a result, BPA recognized a noncash gain of $0.2 million. During fiscal year 2017, BPA did not call any such bonds.

During fiscal years 2018 and 2017, BPA refinanced $34.0 million and $96.1 million of U.S. Treasury bonds in noncash transactions with the U.S. Treasury, which resulted in no gain or loss for either year. BPA does not report these refinanced bonds as part of its annual payment to the U.S. Treasury.

Federal appropriations

Federal appropriations reflect the responsibility that BPA has to repay congressionally appropriated amounts in the FCRPS. Federal appropriations repayment obligations consist primarily of the remaining unpaid power portion of USACE and Reclamation capital investments funded through congressional appropriations and include appropriations for Columbia River Fish Mitigation 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 to the U.S. Treasury 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 paid 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 early in fiscal years 2018 and 2017. 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 capital leases	Future minimum lease payments under capital leases	Borrowings from U.S. Treasury	Federal appropriations	Total
2019	$ 585.8	$ 69.9	$ 574.9	$ -	$ 1,230.6
2020	386.0	435.5	389.0	-	1,210.5
2021	383.0	623.7	280.0	-	1,286.7
2022	383.4	304.2	247.0	0.4	935.0
2023	398.0	99.7	250.0	-	747.7
2024 and thereafter	3,514.4	973.1	3,789.7	1,791.3	10,068.5
Total	$ 5,650.6	$ 2,506.1	$ 5,530.6	$ 1,791.7	$ 15,479.0
Less: Executory costs	-	25.5	-	-	25.5
Less: Amount representing interest	-	420.7	-	-	420.7
Less: Unamortized debt issuance cost	0.8	-	-	-	0.8
Present value of debt	5,649.8	2,059.9	5,530.6	1,791.7	15,032.0
Less: Current portion	585.8	12.5	574.9	-	1,173.2
Long-term debt	$ 5,064.0	$ 2,047.4	$ 4,955.7	$ 1,791.7	$ 13,858.8

Fair value of debt and appropriations

See Note 12, 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.

8. 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 agreements with NIFC obligate 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 periods 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 $20.4 million and Nonfederal debt of $118.8 million as of both Sept. 30, 2018, and 2017. 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 7, 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 $21.8 million, $19.8 million and $21.6 million in fiscal years 2018, 2017 and 2016, respectively. These expenses were recorded to operations and maintenance as BPA management considers the related purchases to be part of the FCRPS resource pool.

9. Residential Exchange Program

REP SCHEDULED AMOUNTS

As of Sept. 30 — millions of dollars	
2019	$ 232.2
2020	245.2
2021	245.2
2022	259.0
2023	259.0
2024 through 2028	1,405.5
Subtotal of annual payments	2,646.1
Less: Discount for present value	389.4
IOU exchange benefits	$ 2,256.7

BACKGROUND

In 1981 and as provided in the Northwest Power Act, BPA began to implement the 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.

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 February 2011 the parties reached a final settlement agreement – the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement), and in July 2011 BPA also signed the 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, 2018, totaling $2.65 billion. Amounts recorded of $2.26 billion at Sept. 30, 2018, represent the present value of future cash outflows for these IOUs exchange benefits.

REP SETTLEMENT AGREEMENT REFUND AMOUNTS

In addition to Scheduled Amounts, the 2012 REP Settlement Agreement calls for Refund Amounts to be paid to COUs in the amount of $76.5 million each year from fiscal year 2012 through fiscal year 2019. The Refund Amounts were established as a regulatory asset and regulatory liability for the refunds that will be provided to COU customers as bill credits. The 2012 REP Settlement Agreement established Refund Amounts totaling $612.3 million, with remaining refunds as of Sept. 30, 2018, totaling $76.5 million. Amounts recorded as a regulatory liability of $75.7 million at Sept. 30, 2018, represent the present value of future cash flows for the amounts to be refunded to COUs.

10. Deferred Credits and Other

As of Sept. 30 — millions of dollars	2018	2017
Customer reimbursable projects	$ 199.8	$ 191.8
Interconnection agreements	182.6	134.6
Third AC Intertie capacity agreements	95.4	94.9
Federal Employees' Compensation Act	27.0	29.6
Fiber optic leasing fees	13.3	15.3
Derivative instruments	7.3	10.7
Other	7.1	7.1
Legal claims and settlements	—	35.0
Total	$ 532.5	$ 519.0

Deferred Credits and Other include the following items:

"**Customer reimbursable projects**" consist of advances received from customers where either the customer or BPA will own the resulting asset. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, the revenue is recognized over the life of the asset once the corresponding asset is placed in service.

“**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.

“**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.

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

“**Fiber optic leasing fees**” reflect unearned revenue related to the leasing of fiber optic cables. Revenue is recognized over the lease terms extending through 2024.

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

11. 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 12, Fair Value Measurements. BPA has formalized 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 2018, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2018, BPA had $48.0 million in credit exposure related to purchase and sale contracts after taking into account netting rights. Of this credit exposure, $14.4 million was related to sub-investment grade counterparties who provided letters of credit that exceed BPA's exposure to these counterparties. 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. These U.S. Treasury investments earn interest that is correlated, but not identical, to the interest rate paid on U.S. Treasury variable rate debt. (See Note 3, Investments in U.S. Treasury Securities and Note 7, Debt and Appropriations.) Energy Northwest may also issue variable rate debt for which BPA is expected to fund the repayment. No variable rate debt has been issued in connection with Energy Northwest or the Lease-Purchase Program.

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 12, Fair Value Measurements.)

As of Sept. 30, 2018, the derivative commodity contracts recorded at fair value totaled 3.3 million megawatt hours (MWh), gross basis, with delivery months extending to December 2019.

On the Combined Balance Sheets, BPA reports gross fair value amounts of derivative instruments subject to a master netting arrangement, excluding contracts designated as normal purchases or normal sales. (See Note 6, Deferred Charges and Other and Note 10, 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 netted by counterparty, BPA's derivative position would have resulted in assets of $16.5 million and $59.2 million, and liabilities of $7.1 million and $10.7 million as of Sept. 30, 2018, and 2017, respectively. (See Note 4, Effects of Regulation.)

12. 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. Instruments categorized in Level 3 include long-dated and modeled commodity contracts where inputs into the valuation are adjusted market prices plus an adder.

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, or on BPA’s own credit spread when in an unrealized loss 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, 2018, and 2017. There were no transfers between Level 1, Level 2 or Level 3 during fiscal years 2018 and 2017.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2018 — millions of dollars

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity index funds	$ 280.0	$ —	$ —	$ 280.0
Bond index funds	50.7	—	—	50.7
Cash and cash equivalents	30.2	—	—	30.2
U.S. government obligation mutual funds	16.7	—	—	16.7
Lease-Purchase trust funds				
U.S. government obligations	—	88.0	—	88.0
Corporate obligations	—	7.5	—	7.5
Derivative instruments [1]				
Commodity contracts	0.1	12.6	3.9	16.6
Total	$ 377.7	$ 108.1	$ 3.9	$ 489.7
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ —	$ (7.2)	$ (0.1)	$ (7.3)
Total	$ —	$ (7.2)	$ (0.1)	$ (7.3)

As *of Sept. 30, 2017 — millions of dollars*

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity index funds	$ 266.3	$ —	$ —	$ 266.3
Bond index funds	60.9	—	—	60.9
U.S. government obligation mutual funds	19.7	—	—	19.7
Lease-Purchase trust funds				
U.S. government obligations	—	120.3	—	120.3
Corporate obligations	—	19.6	—	19.6
Municipal obligations	—	4.6	—	4.6
Derivative instruments [1]				
Commodity contracts	—	57.6	1.6	59.2
Total	$ 346.9	$ 202.1	$ 1.6	$ 550.6
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ (0.1)	$ (10.6)	$ —	$ (10.7)
Total	$ (0.1)	$ (10.6)	$ —	$ (10.7)

[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 11, Risk Management and Derivative Instruments for more information related to BPA's risk management strategy and use of derivative instruments.

Level 3 derivative commodity contracts are 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; therefore, they are considered unobservable. Forward prices are considered a key component to contract valuations. All valuation pricing data is generated internally by BPA's risk management organization.

The risk management organization constructs the forward price curve 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	2018	2017
Beginning Balance	$ 1.6	$ —
Changes in unrealized gains (losses)[1]	2.2	1.6
Ending Balance	$ 3.8	$ 1.6

[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	2018		2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Nonfederal Debt				
Nonfederal generation:				
Columbia Generating Station	$ 3,468.5	$ 3,579.8	$ 3,853.6	$ 4,178.2
Cowlitz Falls Project	72.1	79.9	75.6	88.2
Terminated nonfederal generation:				
Nuclear Project 1	795.6	897.2	838.5	988.5
Nuclear Project 3	914.1	1,060.4	1,044.2	1,170.7
Northern Wasco Hydro Project	11.4	12.2	12.8	14.2
Lease-Purchase Program:				
NIFC debt	118.8	134.6	118.8	143.4
Other financial liability	21.2	21.2	—	—
Customer prepaid power purchases	248.1	248.1	267.1	267.1
Federal debt				
Borrowings from U.S. Treasury	$ 5,530.6	$ 5,720.9	$ 5,008.7	$ 5,424.0

The fair value measurements described above are considered Level 2 in the fair value hierarchy.

The fair value of Nonfederal debt, excluding the Customer prepaid power purchases, is 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 terms of a transmission construction agreement that BPA signed with a customer in fiscal year 2018 and is equal to the carrying value.

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 prepay 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, 2018, and 2017.

13. 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. BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp fluctuates because it is in part dependent on river flows and water conditions. As of Sept. 30, 2018, BPA has long-term fish and wildlife agreements with estimated contractual commitments of $288 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.

In October 2018, BPA and its federal partners USACE and Reclamation signed extension agreements with current Accords partners, namely certain states and tribes, to extend the Columbia Basin Fish Accords. The existing agreements expired Sept. 30, 2018, and were extended from October 2018 until Sept. 30, 2022, at the latest. The extension agreements commit nearly $450 million for fish and wildlife protection and mitigation, which is likely to result in future expenses or regulatory assets. No amounts relating to the extension agreements were recognized in the fiscal year 2018 financial statements, as they were executed subsequent to the fiscal year end.

IRRIGATION ASSISTANCE

Scheduled distributions

As of Sept. 30 — millions of dollars	
2019	$ 56.6
2020	24.3
2021	14.8
2022	16.0
2023	12.9
2024 through 2045	239.4
Total	$ 364.0

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 $364.0 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

As of Sept. 30 — millions of dollars	
2019	$ 77.6
2020	43.9
2021	33.6
Total	$ 155.1

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 of known costs that are currently in place to assist in meeting expected future obligations under BPA's current long-term power sales contracts. Included are two purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal year 2019 and two purchases to meet load obligations in Idaho. The expenses associated with Tier 2 purchases to meet prior commitments were $29.9 million, $26.6 million and $22.1 million for fiscal years 2018, 2017 and 2016, respectively. The expenses associated with the Idaho purchases, which are not included in the Tier 2 amounts, commenced July 1, 2016, and were $44.2 million, $45.3 million and $9.0 million for fiscal years 2018, 2017 and 2016, 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 Seventh Power Plan in fiscal year 2016. These initiatives and activities are often executed via conservation commitments made by BPA to its customers through $78 million of 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 2022.

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 include: 1) Primary Property and Decontamination Liability Insurance; 2) Decontamination Liability, Decommissioning Liability and Excess Property Insurance; and 3) NEIL I Accidental Outage Insurance.

Under each insurance policy, BPA could be subject to a retrospective premium assessment in the event that a member-insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Liability Insurance policy is $19.3 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $6.5 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $5.1 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $450.0 million, BPA could be subject to a retrospective assessment of up to $121.3 million limited to $19.0 million per incident within one calendar year. Assessments would be included in BPA's costs and recovered through rates. As of Sept. 30, 2018, there have been no assessments to 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, 2018, 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.

LITIGATION

Southern California Edison

Southern California Edison (SCE) filed two separate actions in the U.S. Court of Federal Claims against BPA related to a power sales and exchange agreement (Sale and Exchange Agreement) between BPA and SCE. The actions challenged: 1) BPA's decision to convert the contract from a sale of power to an exchange of power as provided for under the terms of the contract (Conversion Claim); and 2) BPA's termination of the Sales and Exchange Agreement due to SCE's nonperformance (Termination Claim).

In 2006, BPA and SCE executed an agreement to settle the claims wherein BPA would make a payment of $28.5 million plus applicable interest to SCE if certain identified conditions were met, including a final resolution of BPA's claims pending in the California refund proceedings and related litigation as discussed below. As of Sept. 30, 2017, BPA had recorded a liability of $35.0 million, including interest, on the basis that all conditions had been met except the final resolution in the California refund proceedings and related litigation, which management considered probable. BPA had also reported an offsetting regulatory asset. In May 2018, the California refund settlement (as discussed below) was approved by FERC and $41.1 million was transferred from the California Power Exchange escrow accounts to pay SCE and satisfy SCE's pending claim. As a result, BPA reduced its 2006 SCE settlement liability and offsetting regulatory asset to $0 during fiscal year 2018 with no impact to net revenues.

California parties' refund claims

BPA was a party to proceedings at FERC that sought refunds for sales into markets operated by the California Independent System Operator and the California Power Exchange during the California energy crisis of 2000-2001. In BPA v. FERC, 422 F.3d 908 (9th Cir. 2005) the Ninth Circuit Court found that governmental utilities, like BPA, were not subject to FERC's statutory authority to order market participants to pay refunds. As a consequence of the Ninth Circuit Court's decision, three California investor-owned utilities along with the State of California filed breach of contract claims in the United States Court of Federal Claims against BPA. The complaints, filed in 2007, alleged that BPA was contractually obligated to pay refunds on transactions where BPA received amounts in excess of mitigated market clearing prices retroactively established by FERC.

After various legal proceedings, BPA signed a settlement agreement on Feb. 5, 2018, to resolve the California parties' refund claims. The agreement provided for: (i) the transfer of $41.1 million to SCE to resolve the SCE litigation described above, (ii) a payment of $16.3 million to BPA related to interest income due from the California Independent System Operator and the California Power Exchange for power sales that occurred in 2000-2001, and (iii) payments of $457 thousand to other market participants. All of these amounts were paid from the California Power Exchange escrow accounts holding monies due and owing BPA and others in the market related to this matter. The settlement agreement was approved by FERC on May 3, 2018, and on May 25, 2018, BPA received $16.3 million under the settlement. As a result, all remaining claims were withdrawn. BPA had previously accrued $16.0 million as a settlement receivable and interest income, and the $300 thousand increase represents the fiscal year 2018 impact to interest income.

Rates

BPA's rates are frequently the subject of litigation. Most of the litigation 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 legal claims, actions and complaints, including litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts. Management is unable to predict whether the FCRPS will avoid adverse outcomes in these legal matters; however, management believes that disposition of pending matters will not have a materially adverse effect on the FCRPS financial position or results of operations for fiscal year 2018.

Judgments and settlements are included in FCRPS costs and recovered through rates. As of Sept. 30, 2018, no material liability has been recorded for the above legal matters.

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Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Millions of dollars)

	As of March 31, 2019	As of September 30, 2018
Assets		
Utility plant		
Completed plant	**$ 19,511.0**	$ 19,307.4
Accumulated depreciation	**(7,033.4)**	(6,883.4)
Net completed plant	**12,477.6**	12,424.0
Construction work in progress	**1,335.0**	1,290.1
Net utility plant	**13,812.6**	13,714.1
Nonfederal generation	**3,846.4**	3,350.9
Current assets		
Cash and cash equivalents	**746.6**	804.2
Short-term investments in U.S. Treasury securities	**-**	40.2
Accounts receivable, net of allowance	**41.9**	75.2
Accrued unbilled revenues	**328.3**	292.4
Materials and supplies, at average cost	**108.7**	109.1
Prepaid expenses	**160.5**	48.2
Total current assets	**1,386.0**	1,369.3
Other assets		
Regulatory assets	**5,433.2**	5,587.7
Nonfederal nuclear decommissioning trusts	**375.2**	377.6
Deferred charges and other	**135.5**	176.8
Total other assets	**5,943.9**	6,142.1
Total assets	**$ 24,988.9**	$ 24,576.4
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 4,266.2**	$ 4,123.8
Debt		
Federal appropriations	**1,814.9**	1,791.7
Borrowings from U.S. Treasury	**4,824.7**	4,955.7
Nonfederal debt	**7,016.8**	7,111.4
Total capitalization and long-term liabilities	**17,922.6**	17,982.6
Commitments and contingencies (See Note 13 to 2018 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	**473.9**	574.9
Nonfederal debt	**748.8**	598.3
Accounts payable and other	**479.1**	511.4
Total current liabilities	**1,701.8**	1,684.6
Other liabilities		
Regulatory liabilities	**1,841.6**	1,912.0
IOU exchange benefits	**2,161.2**	2,256.7
Asset retirement obligations	**805.5**	208.0
Deferred credits and other	**556.2**	532.5
Total other liabilities	**5,364.5**	4,909.2
Total capitalization and liabilities	**$ 24,988.9**	$ 24,576.4

This BPA-approved financial information was made publicly available on 4-26-2019.

Federal Columbia River Power System
Combined Statements of Revenues and Expenses (Unaudited)
(Millions of dollars)

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Fiscal Year-to-Date Ended March 31, 2019	Fiscal Year-to-Date Ended March 31, 2018
Operating revenues				
Sales	**$ 966.5**	$ 1,013.3	**$ 1,831.7**	$ 1,867.4
U.S. Treasury credits	**32.3**	20.4	**77.2**	49.4
Total operating revenues	**998.8**	1,033.7	**1,908.9**	1,916.8
Operating expenses				
Operations and maintenance	**529.5**	524.3	**1,045.8**	1,002.6
Purchased power	**189.0**	20.1	**249.5**	63.3
Nonfederal projects	**52.0**	73.5	**103.9**	147.0
Depreciation and amortization	**132.4**	124.6	**264.3**	246.6
Total operating expenses	**902.9**	742.5	**1,663.5**	1,459.5
Net operating revenues	**95.9**	291.2	**245.4**	457.3
Interest expense and (income)				
Interest expense	**61.1**	60.1	**123.3**	119.9
Allowance for funds used during construction	**(7.1)**	(7.9)	**(15.7)**	(16.4)
Interest income	**(2.0)**	(1.1)	**(4.6)**	(1.8)
Net interest expense	**52.0**	51.1	**103.0**	101.7
Net revenues	**$ 43.9**	$ 240.1	**$ 142.4**	$ 355.6

BAKER TILLY

INDEPENDENT AUDITORS' REPORT

To the Executive Board
Energy Northwest
Richland, Washington

We have audited the accompanying financial statements of Energy Northwest, as of and for the year ended June 30, 2018, and the related notes to the financial statements, which collectively comprise Energy Northwest's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Northwest as of June 30, 2018, and the respective changes in financial position and cash flows thereof for the year then ended in accordance with accounting principles generally accepted in the United States of America.

BAKER TILLY

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, schedule of proportionate share of net pension liability, and schedule of contributions, which are considered required supplementary information, be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our 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.

Baker Tilly Virchow Krause, LLP

Madison, Wisconsin
September 27, 2018

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, 2018, with the basic financial statements for the FY ended June 30, 2017.

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 total only for Energy Northwest, as a whole, for FY 2018 and FY 2017.

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, 2018 and 2017. 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, 2018 and 2017 (Dollars in thousands)

		2017		2018		Change
Assets						
Current Assets	$	644,343	$	556,457	$	(87,886)
Restricted Assets						
Special Funds		169,930		134,502		(35,428)
Debt Service Funds		160,169		335,640		175,471
Net Plant		1,661,945		1,692,350		30,405
Nuclear Fuel		891,014		841,196		(49,818)
Long-Term Receivables		21		22		1
Other Charges		3,203,592		3,065,680		(137,912)
TOTAL ASSETS		6,731,014		6,625,847		(105,167)
DEFERRED OUTFLOWS OF RESOURCES		46,227		37,919		(8,308)
TOTAL ASSETS AND DEFERRED OUTFLOWS	$	6,777,241	$	6,663,766	$	(113,475)
Current Liabilities	$	546,588	$	589,516	$	42,928
Restricted Liabilities						
Special Funds		128		85		(43)
Debt Service Funds		124,502		122,992		(1,510)
Long-Term Debt		5,804,189		5,651,796		(152,393)
Other Long-Term Liabilities		292,302		274,440		(17,862)
Other Credits		6,257		6,431		174
Net Position						
Invested in capital assets, net of related debt		(40,216)		(38,999)		1,217
Restricted, net		18,819		19,101		282
Unrestricted, net		14,112		16,248		2,136
TOTAL LIABILITIES AND NET POSITION		6,766,681		6,641,610		(125,071)
DEFERRED INFLOWS OF RESOURCES		10,560		22,156		11,596
TOTAL LIABILITIES, NET POSITION AND DEFERRED INFLOWS	$	6,777,241	$	6,663,766	$	(113,475)
Operating Revenues	$	516,112	$	512,319	$	(3,793)
Operating Expenses		402,523		391,442		(11,081)
Net Operating Revenues		113,589		120,877		7,288
Other Income and Expenses		(109,423)		(117,242)		(7,819)
Beginning Net Position		(11,451)		(7,285)		4,166
ENDING NET POSITION	$	(7,285)	$	(3,650)	$	3,635

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 9,565 gigawatt-hours (GWh) of electricity in FY 2018, as compared to 8,640 GWh of electricity in FY 2017. The generation for FY 2018 included economic dispatch of 204 GWh as compared to 174 GWh and coast down credit of 93 GWh for FY 2017. Coast down credit did not occur in FY 2018 due to a non-refueling year. Both the economic dispatch and coast down credit were due to BPA requested decreases in generation for regional power management. The FY 2018 generation increase of 10.7 percent was due to FY 2017 being a refueling year (R-23) combined with FY 2018 being the fifth highest fiscal year generation on record. FY 2018 generation was 0.5% below budgeted generation for the year due to Columbia going offline for a brief period at the end of August of 2017. Columbia resumed 100% operation on September 7. In May of 2018, the there was a main transformer trip due to a grid fault which resulted in a plant shutdown. Columbia resumed operations at 65% on May 25 and 100% operations on June 11. BPA requested the managed ramp up of power and granted Columbia 156 GWh of economic dispatch due to the grid fault and request ramp-up. The small outage and lost generation during FY 18 was mostly negated by the continued additional MWe gained because of the Leading Edge Flow Meter Project and valve work completed in the FY 2015 refueling outage (R-22) and additional work completed in the FY 2017 refueling outage (R-23). Columbia, because of the past two refueling outages work completed, continues the capability 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 2018 was 3.56 cents per kilowatt-hour (kWh) as compared with 5.04 cents per kWh in FY 2017. The industry cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. The FY 2017 cost of power decrease of 29.4 percent was due to the increased generation levels budgeted for and attained in FY 2018 along with the decreased generation impacts in FY 2017 due to the R-23 refueling outage. FY 2018 cost of power was 2.60 percent below budget reflecting continued cost control and reliable and predictable operations and generation.

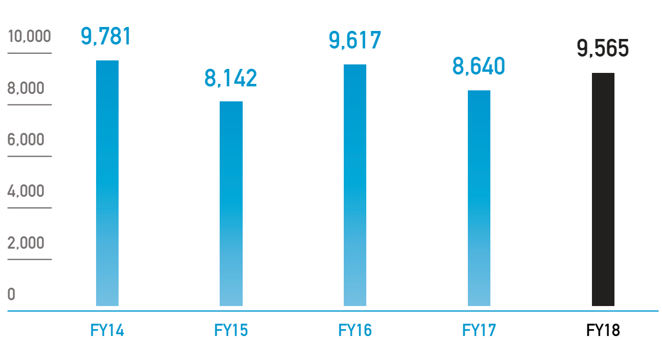
Assets, Liabilities, and Net Position Analysis

The net increase to Utility Plant (plant) and Construction Work In Progress (CWIP) from FY 2017 to FY 2018 (excluding nuclear fuel) was $38.0 million. The changes to plant and CWIP were comprised of additions to plant of $82.4 million and a decrease to CWIP of $37.9 million. Remaining change was the period effect of depreciation of $82.3 million.

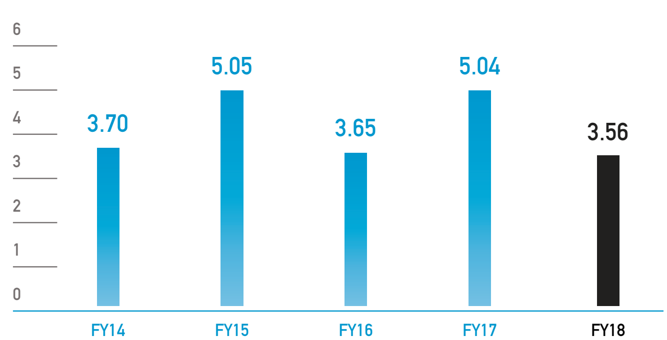
The FY 2018 CWIP balance of $78.3 million consisted of 13 major projects of at least $2.0 million: Low pressure turbine replacement, Fukishima impacts, Plant fire detection upgrades, ISFSI storage pad expansion, Pumps and motors, Asset Suite software upgrade, License renewal implementation, Plant process computer replacement, Control rod drive refurbishments, Stack monitor upgrade, Fire probability risk assessment upgrade, and plant elevator modernization. These projects resulted in 80% of the current CWIP balance. The remaining 20 percent are made up of 38 separate projects.

Current assets decreased $19.6 million in FY 2018 to $493.7 million. The main driver for the decrease was the FY 2018 cask campaign ($29.2 million) that resulted in a movement of nine canisters with used fuel assemblies from the refuel floor of

Columbia Generating Station
Net Generation - Gwhrs



Columbia Generating Station
Cost of Power - Cents/kWh



the reactor building to the ISFSI. The FY 2018 cask campaign was the fifth for Columbia since building the ISFSI in 2001; there have been 36 casks moved to date with campaigns taking place in 2002, 2004, 2008 and 2014. The remainder of the change for materials and supplies was an increase to inventory of $9.5 million accounting for the overall decrease in materials and supplies of $19.7 million. Other changes in current assets were increases to prepayments of $0.9 million, increases to accounts and other receivables of $3.3 million, and a decrease to cash of $4.1 million. These minor changes to accounts combined with the drivers in materials and supplies accounted for the overall change to current assets of $19.6 million.

Restricted assets increased $172.7 million to $387.1 million in FY 2018 due to the FY 2018 bond funding activities and bond restructuring associated with the regional cooperation debt program.

Other charges decreased $93.1 million in FY 2018 from $1,167.9 million to $1,074.8 million. The decrease 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 decreased $7.6 million in FY 2018 from $42.9 million to $35.3 million. The changes were a decrease of $4.4 million due to the recognition of a deferred pension outflow in accordance with GASB No. 68 and a decrease of $3.1 million to unamortized loss on refunding associated with the 2018 bond activity.

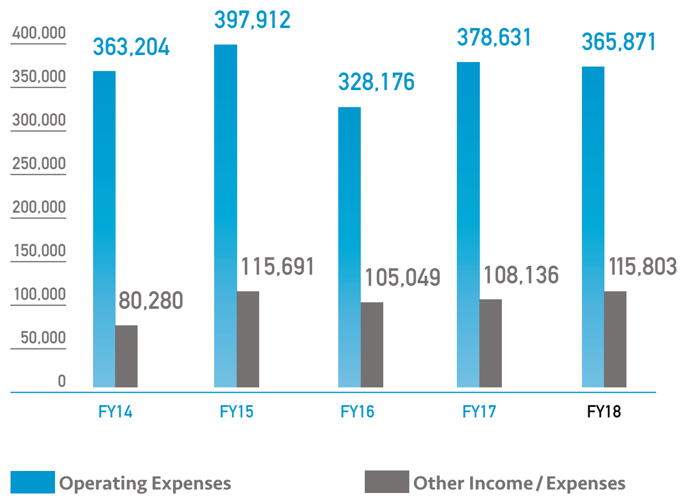
Current liabilities increased $142.6 million in FY 2018 to $535.8 million. The major reason for the increase ($180.6 million) was due to the current portion of debt per the maturity schedule for bonds. The change in current debt was offset by a decrease to current notes payable that funded operations and FY 2018 bond interest costs of $8.0 million, decreases due to timing of year-end obligations and due to other projects of $24.0 million, and timing of due to participants that resulted in a decrease of $6.0 million.

Restricted liabilities increased $1.4 million in FY 2018 to $75.3 million reflecting the changes in accrued interest on various bond series.

Long-term debt (Bonds Payable) increased $100.6 million in FY 2018 from $3,674.4 million to $3,573.8 million due to the FY 2018 bond restructuring and funding activities associated with the regional cooperation debt program.

Other long-term liabilities decreased $14.4 million in FY 2018 to $263.5 million. The major driver was a decrease in the pension liability in accordance with GASB No. 68 of $22.4 million offset by an increase in the decommissioning liability of $8.0 million. 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 to the Financial Statements - Commitments and Contingencies - Other Litigation and Commitments.)

Columbia Generating Station
Total Operating Costs (Dollars in thousands)



Deferred inflows increased $11.5 million from $9.5 million in FY 2017 to $21.0 million in FY 2018. An increase of $12.0 million was recognized to deferred pension inflow in accordance with GASB No. 68. A decrease to bond refunding inflows of $0.5 million was due to the FY 2018 bond restructuring and funding activities associated with the regional cooperation debt program. Deferred credits for FY 2018 consisted of unclaimed bearer bonds and remained at the same level as FY 2017.

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 $12.7 million from FY 2017 costs of $378.6 million to $365.9 million in FY 2018. The decreases in costs were due to FY 2018 being a non-refueling year while FY 2017 was a planned refueling year (R-23). The major driver for the decrease was in operations and maintenance, FY 2018 incurred a decrease of $50.9 million in expenses due to the non-refueling year. The decrease was offset by higher fuel costs and generation taxes for FY 2018 of $27.5 million and $1.0 million respectively; both are a result of higher generation numbers for FY 2018 year. Other increases were $5.8 million for depreciation and amortization due to changes in plant assets, increase of $7.2 million to pension expense requirements related to GASB No. 68, and a small increase of $0.4 million for changes to decommissioning as part

C-6

of the asset retirement obligation estimate (See Note 9 to the Financial Statements - Asset Retirement Obligation (ARO)). These increases were offset by a decrease to Administrative and General expenses of $3.8 million for the overall decrease to operating expenses of $12.7 million.

Other Income and Expenses increased $7.7 million from FY 2017 to $115.8 million net expenses in FY 2018. Increases of $14.5 million to bond interest expense decreases of $1.5 million to amortized bond accounts were incurred as part of the FY 2018 planned and approved regional cooperation debt program. Other expenses were offset by the FY 2018 $11.1 million gain on spent fuel litigation settlement from the DOE, which was $3.9 million higher than FY 2017. 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 11 to the Financial Statements - Commitments and Contingencies - Other Litigation and Commitments.) 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 SWU sale related to the TVA fuel contract (See Note 12 to the Financial Statements - Nuclear Fuel). The FY 2018 gain on SWU sale was $5.3 million, an increase of $0.6 million over the FY 2017 SWU sale gain. The remaining change of $0.8 million was due to increases in investment income for FY 2018 above the FY 2017 levels.

Columbia's total operating revenue decreased from $486.8 million in FY 2017 to $480.6 million in FY 2018. The decrease of $6.2 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 to the Financial Statements - Net Billing.)

which may lower the generating capacity for Packwood.

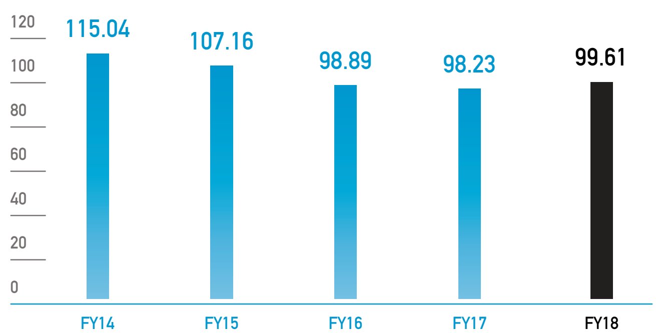
Packwood's cost performance is measured by the cost of power indicator. The cost of power for FY 2018 was $2.39 cents per kWh as compared to $2.36 cents per kWh in FY 2017. The cost of power fluctuates year-to-year depending on various factors such as outage, maintenance, generation, and other operating costs. The slight increase (1.3%) in the FY 2018 cost of power occurred due to minor increases in operations and maintenance that was not offset by a larger increase in generation.

Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows remained relatively steady from FY 2017 decreasing by $9 thousand. Deferred pension outflow decreased $15 thousand and net plant decreased $19 thousand. Increases of $25 thousand to current assets accounted for the remaining change in assets and deferred outflows.

The Packwood Lake Hydroelectric Project

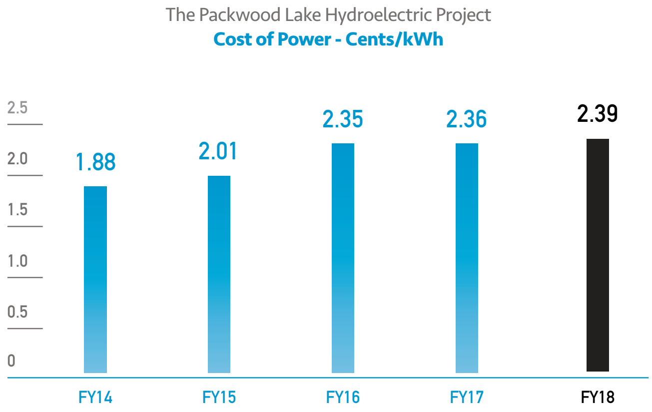
Net Generation - Gwhrs

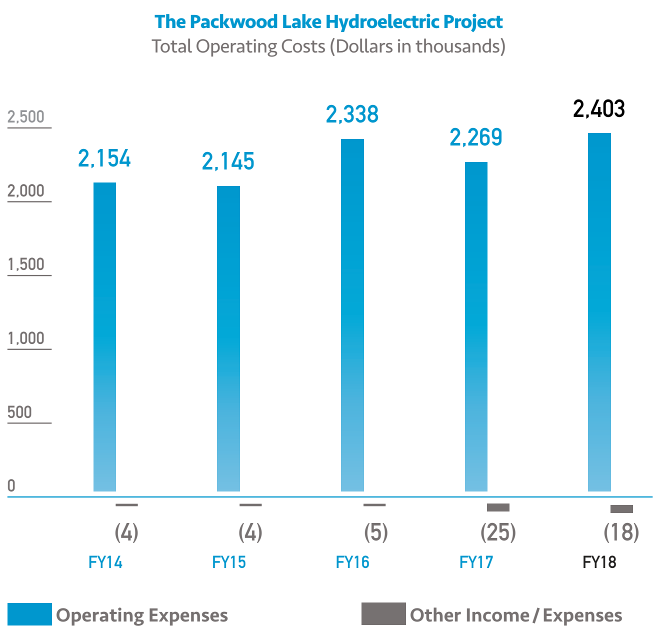


PACKWOOD LAKE HYDROELECTRIC PROJECT

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 99.61 GWh of electricity in FY 2018 versus 98.23 GWh in FY 2017. The slight generation increase of 1.4 percent was due to more favorable snow conditions and runoff in FY 2018 as compared to FY 2017. FY 2018 was the 19th highest for generation on record for Packwood as compared to FY 2017 that was the 23rd highest in generation. FY 2018 generation was near the 10-year average of 101.2 GWh and exceeded the life to date average year of 94.37 GWh. There continues to be some relief in generation capacity due to the delay in new license requirements (See Note 1 to the Financial Statements)

There was an increase to other credits of $21 thousand (increase to billings in excess of cost of $88K with a decrease to unclaimed bearer bonds of $67 thousand). Current liabilities increased $6 thousand, deferred pension inflows increased $41 thousand and long-term pension liability decreased $77 thousand to account for the net change of $9 thousand to liabilities, net position and deferred inflows. Pension deferrals and pension liability are recognized in accordance with GASB No. 68. Packwood has incurred $3.7 million in relicensing costs through FY 2018 with no new costs incurred for FY 2018. These costs are shown as Other Charges on the Statement





of Net Position. Packwood has been operating under a 50-year license issued by 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 March 4, 2010, FERC issued a one-year extension to operate under the original license, which is indefinitely extended for continued operations until a formal decision is issued by FERC and a new operating license is 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. As of June 30, 2018, Packwood continues to be relicensed under the extended agreement from March 2010.

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 $0.1 million FY 2017 to FY 2018 due to contractor support on a forced outage in March of 2018. Other Income and Expense decreased $6 thousand in FY 2018 due to slightly lower investment income ($1 thousand) and no gains on disposals recorded in FY 2018 while FY 2017 had $5 thousand in reported gains.

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, 2018 there is $6.1 million recorded as other credits that are deferred revenues in excess of costs being kept within the project. Packwood participants are currently taking 100 percent 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 percent 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 11 to the Financial Statements.)

Assets, Liabilities, and Net Position Analysis

Total Assets and deferred outflows decreased $63.8 million from $1.0 billion in FY 2017 to $942.2 million in FY 2018. Specific drivers for the decrease was a liquidation of the FY 2017 accounts receivable related to the BPA draw on participant billing of $43.0 million to zero in FY 2018, a decrease of $2.9 million in restricted assets due to FY 2018 bond activity, and a decrease of $17.8 million in costs in excess of billing. There were no major changes in balances for deferred outflows of resources.

Long-term debt remained unchanged at $795.6 million due to maturity schedule with a decrease related to unamortized debt expenses of $15.2 million and a decrease to debt service funds of $2.8 million. Current liabilities decrease from $43.5 million in FY 2017 to $0.2 million in FY 2018 as the notes payable balance of $42.9 million related to bond financing was liquidated. Bond activity with debt accounts and notes payable reflect activity associated with the planned and approved regional cooperation debt program. Remaining decrease to current liabilities of $0.4 million related to accounts payable and accrued expenses. Total long-term liabilities decreased $2.5 million and consisted of activity related to decommissioning; the change reflects accelerated work and updated estimates for decommissioning. There were no major changes in balances for deferred credit or deferred inflows of resources.

Revenue and Expenses Analysis

Other Income and Expenses showed a net decrease to expenses of $3.8 million from $28.4 million in FY 2017 to $24.6 million in FY 2018. Main drivers for the change was a decrease in interest expense and amortization of $2.7 million from FY 2018 bond refunding activity in addition to lower plant preservation and termination costs of $1.1 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 percent 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 11 to the Financial Statements.)

Assets, Liabilities, and Net Position Analysis

Long-term debt decreased $79.7 million from $993.7 million in FY 2017 to $914.0 million in FY 2018 along with an increase related to additional premiums on new debt issued during the year of $52.5 million due to the debt refunding activity associated with the planned and approved regional cooperation debt program.

Current debt per the debt maturity schedule decreased $5.5 million from $17.3 million in FY 2017 to $11.8 million in FY 2018 as a result of the FY 2018 refunding activity moving debt out to future periods. Additionally notes payable balance of $50.5 million from FY 2017 to fund FY 2018 interest costs was paid off. Both the refunding and notes payable activities were associated with the planned and approved regional cooperation debt program.

Other changes to liabilities were decreases to accounts payables of $0.2 million for end of year activity and deferred inflows of $0.4 million due to unamortized gain on bond refundings.

Revenue and Expenses Analysis

Overall expenses and revenues increased $0.5 million in FY 2018 due to decreases in interest expense on long-term debt and notes of $1.0 million offset by $1.5 million of increases in bond related amortized accounts.

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 energy business opportunities.

The BDF is managed as an enterprise fund. Five business sectors have been created within the fund: Applied Technology & Innovation, Business Services, Facilities and Leasing, Generation, and Professional 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

Total assets and deferred outflows decreased $0.1 million from $12.7 million in FY 2017 to $12.6 million in FY 2018. There were no significant individual differences in account classifications; the major driver for the decrease was related to a decrease in deferred pension outflow in accordance with GASB No. 68. There was a corresponding decrease to liabilities, net position and deferred inflows of $0.1 million. Current liabilities decreased $0.4 million from FY 2018 due to timing of year-end outstanding items. Long-term liabilities decreased $0.7 million due to net pension. Deferred inflows increased $0.4 million to account for the change in net pension liability in accordance with GASB No. 68. The change in net position of $0.7 million from operations in FY 2018 was similar to the $0.8 million reflected in FY 2017, which reflects continuing margin achievement from the business sectors and overall control of costs.

Revenue and Expenses Analysis

Operating Revenues in FY 2018 totaled $9.7 million as compared to FY 2017 revenues of $8.2 million, an increase of $1.5 million (18.3 percent). Various projects and timing of work were drivers for the marked increase in overall increase in overall revenue for the Business Development Fund and the five business sectors.

The Applied Technology and Innovation sector increased $0.5 million from FY 2017 levels on activity related to the Demand Response Program. The program was new for FY 2017 and involved a Distributed Energy Resource agreement with BPA that ended In September of 2017. The business sector is continuing to explore new developments and possibilities going forward.

The Business Services sector decreased slightly in FY 2018 from $5.8 million in FY 2017 to $5.7 million. The sector continues strong performance with continuing agreements for Calibration Services and Environmental Lab Services.

The Facilities Leasing sector had decreased revenues of $66 thousand as consolidation and downsizing of leasing at the Industrial Development Complex occurred in FY 2018.

The Generation business sector revenues increased $0.3 million from $0.1 million in FY 2017 to $0.4 million in FY 2018. The increase was due to the startup of the Electric Vehicle Infrastructure Transportation Alliance Project (EVITA). EVITA is a result of a grant award from the Washington State Department of Transportation to participate in the project. Energy Northwest will receive $405 thousand in grant monies to develop the EVITA 1 and EVITA 2 projects. The grant proceeds are based on $1.1 million in eligible costs towards the purchase and installation of nine electric vehicle-charging stations located on previously underserved highway corridors in Washington State. Utah Associated Municipal Power Systems (UAMPS) Carbon Free Power and Modular Nuclear increased slightly in FY 2018 ($12 thousand). UAMPS is slated for further development as the Modular Nuclear concept grows and agreements are developed. Energy Northwest is currently supporting development of two solar projects (Neoen and Horn Rapids Solar Storage and Training (HRSST)). Energy Northwest revenues decreased in FY 2018 from $26 thousand to $3 thousand, mostly due to decreased utilization of Energy Northwest personnel for the project. HRSST reported no revenue in FY 2018, similar to FY 2017 that related to the Department of Commerce (Commerce) grant received In FY 2017. The Commerce grant was for development of a four MWdc photovoltaic solar project coupled with a one MW/4 MWh state-of-the-art battery storage. Development and eventual construction of the project continues, Energy Northwest continues to collaborate with the City of Richland for the battery storage portion of the HRSST. No revenues for the HRSST project have occurred due to continued negotiations of final development plans; development with continue in FY 2019 and FY 2020.

The Professional Services business sector revenue increased $0.9 million (10.8%), mostly due to the new FY 2018 project work at the Portland Hydro Project. Portland Hydro is a five-year agreement to operate and maintain the project for the City of Portland. Portland Hydro resulted in $1.2 million in FY 2018 revenues. The Tieton Hydroelectric Project had a slight decrease in revenues of $0.2 million due to a lower volume of special project activity. The remaining decrease of $0.1 million for the Professional Services sector was for various operations and maintenance contracts not achieving desired margins.

Operating costs increased $1.3 million from $9.0 million in FY 2017 to $10.3 million in FY 2018. The 14.4% increase in overall operating costs for the Business Development Fund was a result of additional expenses related to the new Portland Hydro Project and minor increases in additional business support labor and compensation related to all sector activities.

Other Income and Expenses increased $0.3 million in FY 2018 to $1.2 million. The change was a result of pension expense requirements related to GASB No. 68 and a small increase of indirect related expenses.

The Business Development Fund receives contributions from the Internal Service Fund to cover cash needs during startup periods. Initial startup costs are 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 2018, there were no contributions (transfers), which was also the case for FY 2017.

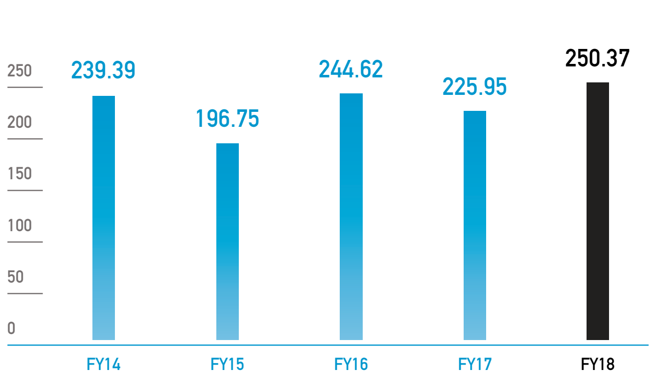
NINE CANYON WIND PROJECT

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 Bonneville Power Administration (BPA) transmission grid via a substation and transmission lines constructed by Benton County Public Utility District.

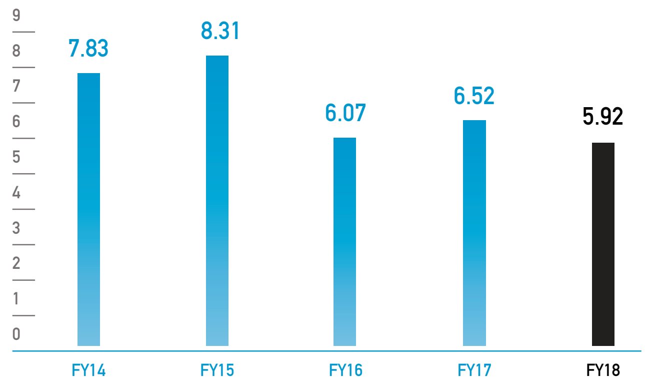
Phase I of Nine Canyon, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 MW, for an aggregate generating capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 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 250.37 GWh of electricity in FY 2018

Nine Canyon Wind Project
Net Generation - Gwhrs



Nine Canyon Wind Project
Cost of Power - Cents/kWh



versus 225.95 GWh in FY 2017, achieving the third highest historical net generation for the project. The increase of 7.6 percent for generation was a result of a higher average wind speed of 3.1% for FY 2018 versus FY 2017 and an improved monthly capacity factor of 30.95 percent for FY 2018 versus 27.74 percent for FY 2017 (increase of 11.6%). Wind speeds in FY 2018 were average as compared against project history; however, the highest capacity factor in the last 5 years and attaining the third highest combined availability for the project to date resulted in the successful generation production.

Nine Canyon's cost performance is measured by the cost of power indicator. The cost of power for FY 2018 was $5.92 cents per kWh as compared to $6.52 cents per kWh in FY 2017. 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 decrease of 9.2 percent in cost of power for FY 2018 was attributable to flat expenses from FY 2017 to FY 2018, higher capacity and combined availability factors due to more favorable wind conditions. The FY 2018 5.92 cents/KWh cost of power was the lowest to date for the project.

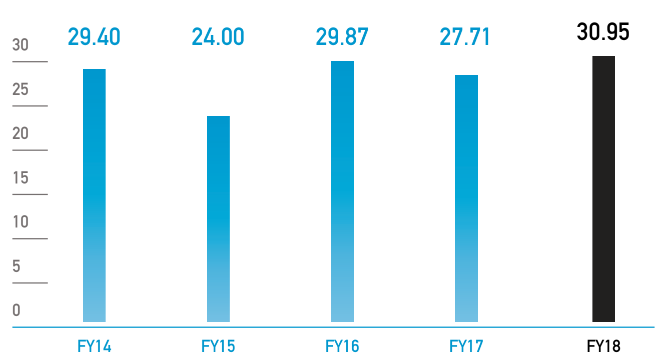
Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows decreased $6.3 million from $89.6 million in FY 2017 to $83.3 million in FY 2018. The major driver for the change in assets was a decrease of $6.9 million in net plant due to accumulated depreciation. The remaining changes consisted of increases to current cash and investments of $0.5 million, increases to restricted (special and debt service funds) of $0.1 million, an increase of $0.3 million in account receivables and supplies and a decrease to deferred outflows for unamortized debt expense of $0.3 million.

There was an overall decrease to liabilities, net position and deferred inflows of $6.3 million. Changes were a decrease to long term debt (including unamortized bond discount/premium) of $9.5 million, increase to current maturities of debt of $0.4 million, decrease to current liabilities of $0.2, decreases to long term liabilities of $0.1 million for pension liability and decommissioning estimates, decrease of $0.2 million accrued debt service interest. The change in net position lowered slightly in FY 2018 from $3.2 million in FY 2017 to $2.9 million from operations in FY 2018. The 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

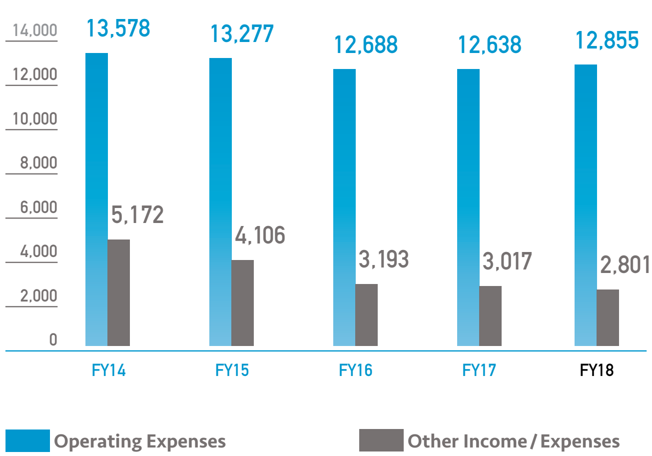
Nine Canyon Wind Project
Capacity Factor (%)



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. The billing rates for the Nine Canyon participants increased 69 percent and 80 percent for Phase I and Phase II participants respectively in FY 2008 in order to cover total project costs, projected out to the 2030 proposed project end date. The increases for FY 2008 were a change from the previous plan where a 3 percent increase each year over the life of the project was projected. Going forward, the increase or decrease in rates will be based on cash requirements of debt repayment and the cost of operations. In FY 2017 Nine Canyon Participants of all three phases realized a 3 percent decrease in rates driven by debt refinancing efforts and cost reduction/ stabilization efforts in recent years. Possible adjustments may be necessary to future rates depending on operating costs.

Nine Canyon Wind Project

Total Operating Costs (Dollars in thousands)



Revenues and Expenses Analysis

Operating revenues decreased $0.3 million from $18.8 million in FY 2017 to $18.5 million in FY 2018. The project received revenue from the billing of the purchasers at an average rate of $70.79 per MWh for FY 2017 as compared to $78.44 per MWh for FY 2018. The decrease in the billed rates was due to increased generation with steady costs as compared to previous years.

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 costs remained relatively steady at $12.8 million from the previous year with a slight increase of $0.3 million. Cost control and increased capacity factor led to the best cost of power achievement to date for the project.

Other income and expenses decreased $0.2 million from $3.0 million in net expenses in FY 2017 to $2.8 million in FY 2018. The decrease of $0.2 million was attributable to bond interest expense and changes in amortized bond expenses. Net income or change in net position of $2.9 million for FY 2018 was a direct result of the planned rate structure with projected treasury savings due to refunding and lower than budgeted operating costs.

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 2018 and is not anticipating receiving any future REPI incentives. The results from FY 2018 reflect the revised rate plan scenario and gradual increase in the return of total net position.

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 to Financial Statements.)

Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows decreased $6.4 million from $58.4 million in FY 2017 to $52.0 million in FY 2018. There was a decrease in due from other business units of $5.5 million and decreases to utility plant of $0.9 million. Other asset items remained relatively steady from the previous year.

The net decrease in net position and liabilities is due to decreases in accounts payable and payroll related liabilities of $5.9 million due to year-end allocation of related expenses and a decrease to due to other projects of $0.4 million. Net position remained relatively unchanged because of FY 2018 activity (increase of $42 thousand).

Revenues and Expenses Analysis

Overall results of operations resulted in a decrease from $148 thousand to $42 thousand in net income for FY 2018. A residual increase in overall expenses resulted in the slight increase of cost of operations

CURRENT DEBT RATINGS (Unaudited)

		Nine Canyon Rating	
Energy Northwest (Long-Term)	Net-Billed Rating	Phase I & II	Phase III
Fitch, Inc.	AA	A-	A-
Moodys Investors Service, Inc. (Moodys)	Aa1	A2	A2
Standard and Poor's Ratings Services (S & P)	AA-	NR	A

STATEMENT OF NET POSITION As of June 30,2018 (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	Eliminations	2018 Combined Total
ASSETS										
CURRENT ASSETS										
Cash	$ 24,428	$ 691	$ 2,612	$ 3,080	$ 1,968	$ 3,344	$ 36,123	$ 2,177	$ -	$ 38,300
Investments	-	1,489	797	-	6,735	9,848	18,869	26,303	-	45,172
Accounts and other receivables	313,522	163	1	-	1,533	142	315,361	186	-	315,547
Due from other business units	-	-	66	108	-	254	428	17,125	(17,553)	-
Materials and supplies	153,397	-	-	-	-	-	153,397	-	-	153,397
Prepayments and other	2,360	18	7	7	4	198	2,594	1,447	-	4,041
TOTAL CURRENT ASSETS	493,707	2,361	3,483	3,195	10,240	13,786	526,772	47,238	(17,553)	556,457
RESTRICTED ASSETS (NOTE 1)										
Special funds										
Cash	13,752	-	-	4,300	-	31	18,083	-	-	18,083
Investments	116,169	-	-	-	-	-	116,169	-	-	116,169
Accounts and other receivables	248	-	-	-	-	2	250	-	-	250
Debt service funds										
Cash	257,012	-	19,687	37,820	-	10,193	324,712	-	-	324,712
Investments	-	-	-	-	-	10,921	10,921	-	-	10,921
Accounts and other receivables	-	-	-	-	-	7	7	-	-	7
TOTAL RESTRICTED ASSETS	387,181	-	19,687	42,120	-	21,154	470,142	-	-	470,142
NON CURRENT ASSETS										
UTILITY PLANT (NOTE 2)										
In service	4,489,282	15,232	-	-	3,863	134,886	4,643,263	41,492	-	4,684,755
Not in service	-	-	29,415	-	-	-	29,415	-	-	29,415
Construction work in progress	78,358	-	-	-	-	-	78,358	-	-	78,358
Accumulated depreciation	(2,930,334)	(13,241)	(29,415)	-	(2,281)	(88,206)	(3,063,477)	(36,701)	-	(3,100,178)
Net Utility Plant	1,637,306	1,991	-	-	1,582	46,680	1,687,559	4,791	-	1,692,350
Nuclear fuel, net of accumulated depreciation	841,196	-	-	-	-	-	841,196	-	-	841,196
LONG TERM RECEIVABLES	-	-	-	-	-	-		22	-	22
TOTAL NONCURRENT ASSETS	2,478,502	1,991	-	-	1,582	46,680	2,528,755	4,813	-	2,533,568
OTHER CHARGES										
Cost in excess of billings	1,074,792	-	918,981	1,068,170	-	-	3,061,943	-	-	3,061,943
Other	-	3,737	-	-	-	-	3,737	-	-	3,737
TOTAL OTHER CHARGES	1,074,792	3,737	918,981	1,068,170	-	-	3,065,680	-	-	3,065,680
TOTAL ASSETS	4,434,182	8,089	942,151	1,113,485	11,822	81,620	6,591,349	52,051	(17,553)	6,625,847
DEFERRED OUTFLOWS OF RESOURCES										
Deferred outflows - unamortized loss on bond refunding	9,979	-	-	-	-	1,426	11,405	-	-	11,405
Deferred pension outflows	25,351	87	74	-	777	225	26,514	-	-	26,514
TOTAL DEFERRED OUTFLOWS OF RESOURCES	35,330	87	74	-	777	1,651	37,919	-	-	37,919
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 4,469,512	$ 8,176	$ 942,225	$ 1,113,485	$ 12,599	$ 83,271	$ 6,629,268	$ 52,051	$ (17,553)	$ 6,663,766

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

STATEMENT OF NET POSITION As of June 30, 2018 (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	Eliminations	2018 Combined Total
LIABILITIES AND NET POSITION										
CURRENT LIABILITIES										
Current maturities of long-term debt	$ 181,725	$ -	$ -	$ 11,855	$ -	$ 8,010	$ 201,590	$ -	$ -	$ 201,590
Current notes payable	302,050	-	-	-	-	-	302,050	-	-	302,050
Accounts payable and accrued expenses	35,366	103	187	17	698	861	37,232	47,100	-	84,332
Due to participants	-	1,544	-	-	-	-	1,544	-	-	1,544
Due to other business units	16,650	44	-	-	431	-	17,125	428	(17,553)	-
TOTAL CURRENT LIABILITIES	535,791	1,691	187	11,872	1,129	8,871	559,541	47,528	(17,553)	589,516
LIABILITIES-PAYABLE FROM RESTRICTED ASSETS (NOTE 1)										
Special funds										
Other Liabilities	-	-	-	-	85	-	85	-	-	85
Debt service funds										
Accrued interest payable	75,287	-	19,687	25,965	-	2,053	122,992	-	-	122,992
TOTAL RESTRICTED LIABILITIES	75,287	-	19,687	25,965	85	2,053	123,077	-	-	123,077
LONG-TERM DEBT (NOTE 5)										
Revenue bonds payable	3,327,525	-	795,580	914,055	-	78,530	5,115,690	-	-	5,115,690
Unamortized (discount)/premium on bonds - net	246,276	-	121,604	161,413	-	6,813	536,106	-	-	536,106
TOTAL LONG-TERM DEBT	3,573,801	-	917,184	1,075,468	-	85,343	5,651,796	-	-	5,651,796
OTHER LONG-TERM LIABILITIES										
Pension liability	99,618	344	292	-	3,052	886	104,192	-	-	104,192
Decommissioning liability	163,821	-	4,696	-	-	1,576	170,093			170,093
Other	72	-	-	-	79	-	151	4	-	155
TOTAL OTHER LONG-TERM LIABILITIES	263,511	344	4,988	-	3,131	2,462	274,436	4	-	274,440
OTHER CREDITS										
Advances from members and others	-	6,069	-	-	-	-	6,069	-	-	6,069
Other	125	-	118	119	-	-	362	-	-	362
TOTAL OTHER CREDITS	125	6,069	118	119	-	-	6,431	-	-	6,431
TOTAL LIABILITIES	4,448,515	8,104	942,164	1,113,424	4,345	98,729	6,615,281	47,532	(17,553)	6,645,260
DEFERRED INFLOWS OF RESOURCES										
Deferred inflows - unamortized gain on bond refunding	276	-	-	61	-	146	483	-	-	483
Deferred pension inflows	20,721	72	61	-	635	184	21,673	-	-	21,673
TOTAL DEFERRED INFLOWS OF RESOURCES	20,997	72	61	61	635	330	22,156	-	-	22,156
NET POSITION										
Net investment in capital assets	-	-	-	-	1,582	(45,394)	(43,812)	4,813	-	(38,999)
Restricted for debt service	-	-	-	-	-	19,101	19,101	-	-	19,101
Unrestricted	-	-	-	-	6,037	10,505	16,542	(294)	-	16,248
NET POSITION	-	-	-	-	7,619	(15,788)	(8,169)	4,519	-	(3,650)
TOTAL LIABILITIES, NET POSITION, AND DEFERRED INFLOWS	$ 4,469,512	$ 8,176	$ 942,225	$ 1,113,485	$ 12,599	$ 83,271	$ 6,629,268	$ 52,051	$ (17,553)	$ 6,663,766

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, 2018 (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	2018 Combined Total
OPERATING REVENUES	$ 481,674	$ 2,384	$ -	$ -	$ 9,721	$ 18,540	$ 512,319	$ -	$ 512,319
OPERATING EXPENSES									
Services to other business units	-	-	-	-	-	-	-	-	-
Nuclear fuel, net	73,928	-	-	-	-	-	73,928	-	73,928
Decommissioning	8,163	-	-	-	-	95	8,258	-	8,258
Depreciation and amortization	85,787	114	-	-	248	6,831	92,980	-	92,980
Operations and maintenance	171,220	2,274	-	-	10,066	5,874	189,434	-	189,434
Administrative & general	21,246	(7)	-	-	-	1	21,240	-	21,240
Generation tax	5,527	21	-	-	-	54	5,602	-	5,602
Total operating expenses	365,871	2,402	-	-	10,314	12,855	391,442	-	391,442
OPERATING INCOME (LOSS)	115,803	(18)	-	-	(593)	5,685	120,877	-	120,877
OTHER INCOME & EXPENSE									
Other	10,951	-	24,637	35,670	1,228	-	72,486	42	72,528
Gain on DOE Settlement	11,139	-	-	-	-	-	11,139	-	11,139
Investment income	1,559	18	38	79	74	90	1,858	-	1,858
Interest expense and debt amortization, net of capitalized interest	(139,452)	-	(24,772)	(35,443)	-	(2,891)	(202,558)	-	(202,558)
Plant preservation and termination costs	-	-	(2,379)	(306)	-	-	(2,685)	-	(2,685)
Depreciation and amortization	-	-	(1)	-	-	-	(1)	-	(1)
Decommissioning	-	-	2,477	-	-	-	2,477	-	2,477
Services to other business units	-	-	-	-	-	-	-	-	-
TOTAL OTHER INCOME & EXPENSE	(115,803)	18	-	-	1,302	(2,801)	(117,284)	42	(117,242)
NET INCOME (LOSS)	-	-	-	-	709	2,884	3,593	42	3,635
TOTAL NET POSITION, BEGINNING OF YEAR	-	-	-	-	6,910	(18,672)	(11,762)	4,477	(7,285)
TOTAL NET POSITION, END OF YEAR	$ -	$ -	$ -	$ -	$ 7,619	$ (15,788)	$ (8,169)	$ 4,519	$ (3,650)

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

STATEMENTS OF CASH FLOWS As of June 30, 2018 (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	2018 Combined Total
CASH FLOWS FROM OPERATING ACTIVITIES								
Operating revenue receipts	$ 587,662	$ 2,630	$ -	$ -	$ 5,363	$ 18,611	$ -	$ 614,266
Cash payments for operating expenses	(255,291)	(2,447)	-	-	(4,904)	(6,165)	-	(268,807)
DOE Cash settlement	-	-	-	-	-	-	-	-
Cash received from TVA fuel activities	25,000	-	-	-	-	-	-	25,000
Cash payments for services net of cash received from other units	-	-	-	-	-	-	140	140
Net cash provided/(used) by operating activities	357,371	183	-	-	459	12,446	140	370,599
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	104,261	-	-	2,161	-	-	-	106,422
Principal paid on revenue bond maturities	(1,135)	-	-	(17,305)	-	(7,640)	-	(26,080)
Payment for bond issuance and financing costs	(3,957)	(13)	(342)	(2,410)	(15)	(53)	-	(6,790)
Proceeds from notes payable	357,050	-	-	-	-	-	-	357,050
Payment for notes payable	(365,000)	-	(42,871)	(50,471)	-	-	-	(458,342)
Interest paid on bonds	(149,969)	-	(42,171)	(50,198)	-	(4,288)	-	(246,626)
Interest paid on notes	(8,062)	-	(719)	(850)	-	-	-	(9,631)
Payment for capital items	(98,391)	(90)	-	-	(254)	(2)	(14)	(98,751)
Cash received from sale of assets	20							20
Nuclear fuel acquisitions	(25,071)	-	-	-	-	-	-	(25,071)
Payments received from BPA for terminated nuclear projects	-	-	83,123	113,055	-	-	-	196,178
Net cash provided/(used) by capital and related financing activities	(190,254)	(103)	(2,980)	(6,018)	(269)	(11,983)	(14)	(211,621)
CASH FLOWS FROM NON-CAPITAL FINANCE ACTIVITIES	-	-	-	-	-	-	-	-
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(126,244)	(2,243)	(3,297)	(6,553)	(10,774)	(28,640)	(15,472)	(193,223)
Sales of investment securities	113,292	1,250	2,900	6,542	6,200	17,581	15,510	163,275
Interest on investments	1,137	22	32	87	117	320	480	2,195
Net cash provided/(used) by investing activities	(11,815)	(971)	(365)	76	(4,457)	(10,739)	518	(27,753)
NET INCREASE(DECREASE) IN CASH	155,302	(891)	(3,345)	(5,942)	(4,267)	(10,276)	644	131,225
CASH AT JUNE 30, 2017	139,890	1,582	25,644	51,142	6,235	23,844	1,533	249,870
CASH AT JUNE 30, 2018 (NOTE H)	$ 295,192	$ 691	$ 22,299	$ 45,200	$ 1,968	$ 13,568	$ 2,177	$ 381,095

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

RECONCILIATION OF DIRECT CASH FLOW TO STATEMENT OF NET POSITION								
Cash unrestricted	$ 24,428	$ 691	$ 2,612	$ 3,080	$ 1,968	$ 3,344	$ 2,177	$ 38,300
Cash restricted special funds	$ 13,752	$ -	$ -	$ 4,300	$ -	$ 31	$ -	$ 18,083
Cash restricted debt service funds	$ 257,012	$ -	$ 19,687	$ 37,820	$ -	$ 10,193	$ -	$ 324,712
Total Statement of Net Position cash	$ 295,192	$ 691	$ 22,299	$ 45,200	$ 1,968	$ 13,568	$ 2,177	$ 381,095

STATEMENTS OF CASH FLOWS As of June 30, 2018 (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	2018 Combined Total
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net income/loss from operations	$ 115,803	$ (18)	$ -	$ -	$ (593)	$ 5,685	$ -	$ 120,877
Adjustments to reconcile net operating revenues to cash provided by operating activities:								
Depreciation and amortization	140,309	114	-	-	248	6,831	-	147,502
Decommissioning	8,163	-	-	-	-	95	-	8,258
Non-operating revenues	-	-	-	-	-	-	42	42
Other	(10,977)	(75)	-	-	1,151	302	1,335	(8,264)
Change in operating assets and liabilities:								
Costs in excess of billings	116,669	325	-	-	-	-	-	116,994
Accounts receivable	(4,258)	(64)	-	-	(376)	(188)	(458)	(5,344)
Materials and supplies	19,750	-	-	-	-	-	-	19,750
Prepaid and other assets	(872)	(3)	-	-	(1)	(164)	84	(956)
Due from/to other business units	(6,007)	169	-	-	1,146	(286)	5,039	61
Change in net pension liability and deferrals	(5,962)	(21)	-	-	(183)	(53)	-	(6,219)
Due from/to participants	-	-	-	-	(43)	-	-	(43)
Accounts payable	(15,247)	(244)	-	-	(890)	224	(5,902)	(22,059)
Net cash provided/(used) by operating activities	$ 357,371	$ 183	$ -	$ -	$ 459	$ 12,446	$ 140	$ 370,599
Non-cash activities								
Capitalized interest	$ 2,499	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,499
Bond refunding	$ 540,460	$ -	$ -	$ 470,835	$ -	$ -	$ -	$ 1,011,295
Decommissioning liability adjustment	$ -	$ -	$ 2,477	$ -	$ -	$ -	$ -	$ 2,477
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 March 4, 2010, FERC issued a one-year extension, or until the issuance of a new license for the project or other disposition under the Federal Power Act, whichever comes first. FERC is awaiting issuance of the National Oceanic and Atmospheric Administration's (NOAA) Biological Opinion, after which FERC will complete the final license renewal documentation for Packwood.

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 four main business lines associated with this business unit: General Services and Facilities, Generation, Professional Services, and Business Unit Support.

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 begins on July 1 and ends on June 30. In preparing these financial statements, the company has evaluated events and transactions for potential recognition or disclosure through September 27, 2018, the date of audit opinion issuance.

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 FY 2018 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 and Adopted Guidance:

GASB Statement No. 86, "Certain Debt Extinguishment Issues." The objective of this statement is to improve consistency in accounting and financial reporting for in-substance defeasance of debt by providing guidance for transactions in which cash and other monetary assets acquired with only existing resources—resources other than the proceeds of refunding debt—are placed in an irrevocable trust for the sole purpose of extinguishing debt. This Statement also improves accounting and financial reporting for prepaid insurance on debt that is extinguished and notes to financial statements for debt that is defeased in substance. GASB Statement No. 86 did not impact Energy Northwest.

Issued but not Adopted Guidance:

GASB Statement No. 83, "Certain Asset Retirement Obligations." This statement addresses accounting and financial reporting for certain asset retirement obligations (AROs). GASB Statement No. 83 is effective in fiscal year 2019 for Energy Northwest. Currently the accounting and reporting for AROs is in compliance with FASB ASC 410, "Asset Retirement and Environmental Obligations." (See Note 10) Energy Northwest plans to adopt GASB Statement No. 83 in fiscal year 2019.

GASB Statement No. 84, "Fiduciary Activities." The objective of this Statement is to improve guidance regarding the identification of fiduciary activities for accounting and financial reporting purposes and how those activities should be reported. GASB Statement No. 84 is effective for Energy Northwest in fiscal year 2019. Energy Northwest is currently evaluating the full impact of this statement.

GASB Statement No. 87, "Leases." The objective of this Statement is to better meet the information needs of financial statement users by improving accounting and financial reporting for leases by governments. This statement is effective for Energy Northwest in fiscal year 2021. Energy Northwest is currently evaluating the full impact of this statement.

GASB Statement No. 88, "Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements." The primary objective of this Statement is to improve the information that is disclosed in notes to government financial statements related to debt, including direct borrowings and direct placements. It also clarifies which liabilities governments should include when disclosing information related to debt. This statement is effective for Energy Northwest in fiscal year 2019.

GASB Statement No. 89, "Accounting for Interest Cost Incurred before the End of a Construction Period." The objectives of this Statement are (1) to enhance the relevance and comparability of information about capital assets and the cost of borrowing for a reporting period and (2) to simplify accounting for interest cost incurred before the end of a construction period. This statement is effective for Energy Northwest in fiscal year 2021. (See Note 1 C) Energy Northwest plans to early adopt in fiscal year 2019.

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).

C) Capitalized Interest: Energy Northwest analyzes the gross interest expense relating to the cost of the bond sale, taking into account interest earnings and draws for purchase or construction reimbursements for the purpose of analyzing impact to the recording of capitalized interest. If estimated costs are more than inconsequential, an adjustment is made to allocate capitalized interest to the appropriate plant account. Capitalized interest costs were $2.5 million for utility plant with no capitalized Interest for fuel.

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, including interest are capitalized and carried at cost.

E) Asset Retirement Obligation (ARO's): In the absence of government-specific guidance that directly addresses ARO's, Energy Northwest has elected to follow Accounting Standards Codification (ASC) 410, Asset Retirement and Environmental Obligations as issued by the FASB. ASC 410 allows Energy Northwest to recognize the fair value of a liability associated with the retirement of a long-lived asset, such as: Columbia Generating Station, Nuclear Project No. 1, and Nine Canyon, in the period in which it is incurred (See Note 9). AROs are included in decommissioning liabilities on the statement of net position. GASB Statement No. 83 "Certain Asset Retirement Obligations," addresses accounting and financial reporting for certain asset retirement obligations (AROs) and is effective fiscal year 2019 for Energy Northwest. Energy Northwest will adopt the standard as scheduled.

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 10).

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. They are classified as current or non-current assets as appropriate.

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 2018 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:** Consist of separate operating lease agreements. The total of these leases by business unit and their respective amounts paid per year are listed in the table below:

PROJECTS OPERATING LEASE COSTS (Dollars in thousands)

	2019	2020	2021	2022	2023	2024-28
Columbia	$ 646	$ 646	$ 646	$ 646	$ 646	$ 3,230
Nuclear Project No. 1	60	60	60	60	60	300
Nine Canyon	704	704	704	704	704	3,520
Business Development Fund	35	35	35	35	35	175
Internal Service Fund	134	134	134	134	134	670
Total	$ 1,579	$ 1,579	$ 1,579	$ 1,579	$ 1,579	$ 7,895

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), and other immaterial liabilities. The table on the following page summarizes activities for all long-term liabilities excluding pension and decommissioning liabilities.

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 (BPA). Energy Northwest maintains

LONG-TERM LIABILITIES (Dollars in thousands)

	Balance 6/30/2017	Increase	Decrease	Balance 6/30/2018
Columbia				
Revenue bonds payable	$ 3,488,565	$ 553,810	$ 714,850	$ 3,327,525
Unamortized (discount)/premium on bonds - net	185,868	85,557	25,149	246,276
Current maturities of long-term debt	1,135	181,725	1,135	181,725
Other noncurrent liabilities	63	9	-	72
	$ 3,675,631	$ 821,101	$ 741,134	$ 3,755,598
Nuclear Project No.1				
Revenue bonds payable	$ 795,580	$ -	$ -	$ 795,580
Unamortized (discount)/premium on bonds - net	136,774	-	15,170	121,604
Current maturities of long-term debt	-	-	-	-
	$ 932,354	$ -	$ 15,170	$ 917,184
Nuclear Project No.3				
Revenue bonds payable	$ 993,725	$ 401,535	$ 481,205	$ 914,055
Unamortized (discount)/premium on bonds - net	108,887	69,307	16,781	161,413
Current maturities of long-term debt	17,305	11,855	17,305	11,855
	$ 1,119,917	$ 482,697	$ 515,291	$ 1,087,323
Nine Canyon				
Revenue bonds payable	$ 86,540	$ -	$ 8,010	$ 78,530
Unamortized (discount)/premium on bonds - net	8,250	-	1,437	6,813
Current maturities of long-term debt	7,640	8,010	7,640	8,010
	$ 102,430	$ 8,010	$ 17,087	$ 93,353
Business Development Fund				
Other noncurrent liabilities	$ 95	$ -	$ 16	$ 79
	$ 95	$ -	$ 16	$ 79
Internal Service Fund				
Other noncurrent liabilities	$ 5	$ -	$ 1	$ 4
	$ 5	$ -	$ 1	$ 4

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 BPA.

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 principle 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 $23.2 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, and other pension related costs (See Note 6) as labeled on the Statement of Net Position.

S) Other Charges and Credits for Resources: Other charges of $3.7 million relate to the Packwood relicensing effort. On March 4, 2010, FERC issued a one-year extension to operate under the original license, which is indefinitely extended for continued operations until a formal decision is issued by FERC and a new operating license is 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. Energy Northwest has contacted FERC on eventual licensing timeline; current estimate is early in FY 2019. As of June 30, 2018, Packwood continues to be relicensed under the extended agreement from March 2010.

T) Short-Term Debt: A non-revolving loan was established for Project 1, Columbia, and Project 3 in fiscal year 2017 and was subsequently paid in full during fiscal year 2018. The loan paid in full included separate allocations in the amount of $42.9 million, $365.0 million, and $50.5 million for Project 1, Columbia, and Project 3, respectively. Two new loan agreements were established in fiscal year 2018 for up to $302.1 million in total associated with Columbia; agreements not to exceed $141.0 million and $161.1 to fund operations and maintenance expense and interest expense for Columbia. On June 30, 2018, all $302.1 million had been drawn for Columbia. The short-term loan for up to $141.0 million has a maturity of December 18, 2018 but may be extended for an additional six months with a potential final maturity of June 18, 2019. The short-term loan for up to $161.1 million has a maturity of January 4, 2019 but may be extended for an additional period with a final maturity no later than October 31, 2019. Nine Canyon did not receive short-term financing during fiscal year 2018. These balances (on the following page) are included in current notes payable in the Statement of Net Position.

U) 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.

SHORT-TERM DEBT (Dollars in thousands)

	Balance Outstanding at 6/30/2017	Increases	Decreases	Balance Outstanding 6/30/2018	Balance Available at 6/30/2018
Columbia					
Non-Revolving Loan	$ 310,000	$ 357,050	$ 365,000	$ 302,050	$ -
Nuclear Project No.1					
Non-Revolving Loan	42,871	-	42,871	-	-
Nuclear Project No.3					
Non-Revolving Loan	50,471	-	50,471	-	-
Nine Canyon					
Short-term debt	-	-	-	-	-
Packwood					
Short-term debt	-	-	-	-	-
Business Development					
Short-term debt	-	-	-	-	-
Total	$ 403,342	$ 357,050	$ 458,342	$ 302,050	$ -

NOTE 2 - Utility Plant

Utility plant activity for the year ended June 30, 2018 was as follows:

	Balance 06/30/2017	Capital Acquisitions	Sale or Other Dispositions	Balance 06/30/2018
Columbia				
Generation	$ 4,392,077	$ 85,093	$ (2,656)	$ 4,474,514
Decommissioning	14,768	-	-	14,768
Construction Work-in-Progress	40,419	120,533	(82,594)	78,358
Accumulated Depreciation and Decommissioning	(2,848,019)	(84,971)	2,656	(2,930,334)
Utility Plant, net*	$ 1,599,245	$ 120,655	$ (82,594)	$ 1,637,306
Packwood				
Generation	$ 15,142	$ 90	$ -	$ 15,232
Construction Work-in-Progress	-	90	(90)	-
Accumulated Depreciation	(13,133)	(108)	-	(13,241)
Utility Plant, net	$ 2,009	$ 72	$ (90)	$ 1,991
Business Development				
Generation	$ 3,539	$ 324	$ -	$ 3,863
Construction Work-in-Progress	-	324	(324)	-
Accumulated Depreciation	(2,038)	(243)	-	(2,281)
Utility Plant, net	$ 1,501	$ 405	$ (324)	$ 1,582
Nine Canyon				
Generation	$ 134,031	$ -	$ (6)	$ 134,025
Decommissioning	861	-	-	861
Construction Work-in-Progress	-	-	-	-
Accumulated Depreciation and Decommissioning	(81,359)	(6,853)	6	(88,206)
Utility Plant, net*	$ 53,533	$ (6,853)	$ -	$ 46,680
Internal Service Fund				
Generation	$ 46,226	$ 4	$ (4,738)	$ 41,492
Construction Work-in-Progress	-	4	(4)	-
Accumulated Depreciation	(40,568)	(871)	4,738	(36,701)
Utility Plant, net	$ 5,658	$ (863)	$ (4)	$ 4,791

* 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, EN will not be able to recover the value of its investments or collateral securities in possession of an outside party. EN's investment policy addresses this risk. All securities owned by Energy Northwest are held by a third party custodian, acting as an agent for EN under the terms of a custody agreement.

Fair Value: Energy Northwest investments have been adjusted to reflect available fair value as of June 30, 2018 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 EN fair market measurements are quoted at Level 2.

INVESTMENTS **(Dollars in thousands)**

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia	$ 116,263	$ -	$ (94)	$ 116,169
Packwood	1,490	-	(1)	1,489
Nuclear Project No. 1	798	-	(1)	797
Nuclear Project No. 3	-	-	-	-
Business Development Fund	6,752	1	(18)	6,735
Internal Service Fund	26,755	-	(452)	26,303
Nine Canyon Wind	20,956	12	(199)	20,769

(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 $43.1 million have a maturity beyond 1 year with the longest maturity being May 31st, 2022.

Investment Type	Rating	June 30, 2018
Federal Home Loan Bank	AA+	18%
Federal National Mortgage Assn.	AA+	15%
U.S. Treasury	AA+	67%
		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. 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, 2018 under Resolution Nos. 1214, 1299, 1376, and 1482 respectively.

During the year ended June 30, 2018, Energy Northwest issued, for Columbia 2018-A and 2018-B fixed-rate bonds. Additionally, Energy Northwest issued, for Columbia and Project 3, 2018-C and 2018-D fixed-rate bonds. The Columbia and Project 3 bonds were issued with a coupon interest rate ranging from 2.85 percent to 5.00 percent.

The Series 2018-A bonds issued for Columbia are tax-exempt fixed-rate bonds. Series 2018-B bonds issued for Columbia are taxable fixed-rate bonds. The 2018-A and 2018-B bonds were issued in majority to refund prior Columbia bonds along with the purpose of funding fiscal year 2019 capital related expenses at Columbia. The 2018-A, and 2018-B refunding bonds resulted in a combined economic gain of $6.9 million for Columbia. The Series 2018-C bonds issued for Columbia and Project 3 are tax-exempt fixed-rate bonds. Series 2018-D bonds issued for Columbia and Project 3 are taxable fixed-rate bonds. The 2018-C and 2018-D bonds were issued in majority to refund prior Columbia and Project 3 bonds. The 2018-C and 2018-D refunding bonds resulted in a combined economic gain for Columbia of $3.1 million and a combined economic loss for Project 3 of $0.4 million.

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 2018 defeasements included $309.1 million for Columbia and $469.4 million for Project 3.

The Weighted Average Coupon Interest Rates and Total Defeased Bonds for Columbia and Project 3 2018-A, 2018-B, 2018-C, and 2018-D are presented in the following tables:

Weighted Average Coupon Interest Rate for Refunded Bonds

	2018A	2018B	2018C	2018D
Columbia	2.99%	N/A	4.74%	1.76%
Nuclear Project No. 3	N/A	N/A	4.92%	1.38%
Total	2.99%	N/A	4.85%	1.64%

Weighted Average Coupon Interest Rate for New Bonds

	2018A	2018B	2018C	2018D
Columbia	4.84%	2.85%	5.00%	3.03%
Nuclear Project No. 3	N/A	N/A	4.95%	3.03%
Total	4.84%	2.85%	4.97%	3.03%

Total Defeased (Dollars in thousands)

	2018A	2018B	2018C	2018D	Total
Columbia	$ 261,005	N/A	$ 270,135	$ 1,985	$ 533,125
Nuclear Project No. 3	N/A	N/A	$ 468,465	$ 885	$ 469,350
Total	$ 261,005	N/A	$ 738,600	$ 2,870	$ 1,002,475

2018 Refunding Results

Outstanding principal on revenue and refunding bonds for the various business units as of June 30, 2018, and future debt service requirements for these bonds are presented in the following tables:

2018-A (Tax-Exempt) Transaction	Columbia	Project 3
Cash Flow Difference		
Old debt service cash flows	$ 300,078	$ -
New debt service cash flows	291,650	-
Net Cash Flow Savings (Dissavings)	$ 8,428	$ -
Economic Gain / Loss		
Present value of old debt service cash flows	$ 272,232	$ -
Present value of new debt service cash flows	265,283	-
Economic Gain (Loss)	$ 6,949	$ -

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2018-C (Tax-Exempt) Transaction	Columbia	Project 3
Cash Flow Difference		
Old debt service cash flows	$ 276,861	$ 468,465
New debt service cash flows	376,770	556,586
Net Cash Flow Savings (Dissavings)	$ (99,909)	$ (88,121)
Economic Gain / Loss		
Present value of old debt service cash flows	$ 272,826	$ 467,427
Present value of new debt service cash flows	269,749	467,798
Economic Gain (Loss)	$ 3,077	$ (371)

2018-D (Taxable) Transaction	Columbia	Project 3
Cash Flow Difference		
Old debt service cash flows	$ 1,985	$ 885
New debt service cash flows	2,182	973
Net Cash Flow Savings (Dissavings)	$ (197)	$ (88)
Economic Gain / Loss		
Present value of old debt service cash flows	$ 1,980	$ 883
Present value of new debt service cash flows	1,983	884
Economic Gain (Loss)	$ (3)	$ (1)

Columbia Generating Revenue and Refunding Bonds
(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
2006A	5.00	7-1-2020	434,210	50,000
2006D	5.80	7-1-2023	3,425	3,425
2007B	5.33	7-1-20/2021	10,665	9,935
2008A	5.25	7-1-2018	110,935	775
2008B	5.95	7-1-20/2021	14,850	12,025
2008C	5.00-5.25	7-1-21/2024	37,240	20
2009A	4.00-5.00	7-1-2018	116,425	795
2009B	6.80	7-1-23/2024	18,515	9,780
2009C	4.25-5.00	7-1-20/2024	69,170	41,235
2010B	3.75-4.25	7-1-20/2024	16,005	16,005
2010C	4.52-5.12	7-1-20/2024	75,770	75,770
2010D	5.61-5.71	7-1-23/2024	155,805	155,805
2011A	4.00-5.00	7-1-21/2023	311,245	263,685
2011B	4.19-5.19	7-1-2019	29,920	10,595
2011C	3.55	7-1-2019	4,600	4,600
2012A	5.00	7-1-18/2021	441,240	422,440
2012D	4.00-5.00	7-1-25/2044	34,140	34,140
2012E	2.15-4.14	7-1-18/2037	748,515	723,030
2014A	4.00-5.00	7-1-20/2040	517,720	357,770
2014B	4.05	7-1-2030	90,520	41,515
2015A	4.00-5.00	7-1-21/2038	330,460	330,460
2015B	1.82-3.84	7-1-19/2038	329,175	80,830
2015C	5.00	7-1-30/2031	38,525	38,525
2016A	5.00	7-1-21/2032	89,055	85,690
2016B	1.65-3.2	7-1-19/2028	4,085	2,390
2017A	4.00-5.00	7-1-21/2035	188,130	180,405
2017B	1.90-3.39	7-1-20/2029	3,795	3,795
2018A	3.00-5.00	7-1-21/2034	320,510	320,510
2018B	2.85	7-1-2021	1,410	1,410
2018C	5.00	7-1-21/2034	229,025	229,025
2018D	3.03	7-1-2021	2,865	2,865
Revenue bonds payable				$ 3,509,250

Nuclear Project No. 1 Refunding Revenue Bonds
(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
2014C	5.00	7-1-25/2027	197,110	197,110
2015A	5.00	7-1-27/2028	117,815	117,815
2015C	3.00-5.00	7-1-2025	44,005	44,005
2016A	5.00	7-1-25/2026	195,525	195,525
2016B	1.65	7-1-2019	1,280	1,280
2017A	5.00	7-1-26/2028	237,685	237,685
2017B	1.90-2.94	7-1-20/2025	2,160	2,160
Revenue bonds payable				$ 795,580

Nuclear Project No. 3 Refunding Revenue Bonds
(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
1993C	5.75	7-1-2018	522,853	2,911 (A)
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	1.65-3.05	7-1-19/2027	5,420	5,420
2017A	5.00	7-1-25/2028	154,435	141,780
2017B	1.90-2.94	7-1-20/2025	1,645	1,645
2018C	4.00-5.00	7-1-23/2028	399,155	399,155
2018D	3.03	7-1-2021	2,380	2,380
Compound interest bonds accretion				8,944
Revenue bonds payable				$ 925,910

(A) Compound Interest Bonds

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	7-1-18/2023	13,750	8,310
2014	5.00	7-1-18/2023	36,750	26,150
2015	4.00-5.00	7-1-18/2030	54,895	52,080
Revenue bonds payable				$ 86,540

DEBT SERVICE REQUIREMENTS As of June 30, 2018 (Dollars in thousands)

COLUMBIA GENERATING STATION

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2018 Balance:**	$ 181,705	$ 77,195	$ 258,900
2019	417,255	150,885	568,140
2020	357,510	135,545	493,055
2021	353,380	120,834	474,214
2022	354,780	105,749	460,529
2023	299,770	89,879	389,649
2024-2028	430,550	306,385	736,935
2029-2033	708,055	203,198	911,253
2034-2038	373,590	48,996	422,586
2039-2043	29,010	3,464	32,474
2044	3,645	146	3,791
	$ 3,509,250	$ 1,242,276	$ 4,751,526

* Fiscal year for this report indicates the cash funding requirement year.

** Principal and Interest due July 1, 2018.

NUCLEAR PROJECT NO. 1

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2018 Balance:**	$ -	$ 19,687	$ 19,687
2019	1,280	39,375	40,655
2020	1,635	39,353	40,988
2021	0	39,322	39,322
2022	0	39,323	39,323
2023	0	39,322	39,322
2024-2028	792,665	131,910	924,575
	$ 795,580	$ 348,292	$ 1,143,872

* Fiscal year for this report indicates the cash funding requirement year.

** Principal and Interest due July 1, 2018.

NUCLEAR PROJECT NO. 3

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2018 Balance:**	$ 11,855	$ 25,965	$ 37,820
2019	1,350	45,296	46,646
2020	740	45,274	46,014
2021	2,380	45,259	47,639
2022	0	45,187	45,187
2023	68,275	45,187	113,462
2024-2028	841,310	152,892	994,202
	$ 925,910	$ 405,060	$ 1,330,970

* Fiscal year for this report indicates the cash funding requirement year.

** Principal and Interest due July 1, 2018.

NINE CANYON WIND PROJECT

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2018 Balance:**	$ 8,010	$ 2,053	$ 10,063
2019	8,425	3,705	12,130
2020	8,835	3,296	12,131
2021	9,295	2,855	12,150
2022	9,755	2,404	12,159
2023	10,255	1,916	12,171
2024-2028	21,845	4,981	26,826
2029-2030	10,120	611	10,731
	$ 86,540	$ 21,821	$ 108,361

* Fiscal year for this report indicates the cash funding requirement year.

** Principal and Interest due July 1, 2018.

NOTE 5 - Net Billing

Security - Nuclear Projects Nos. 1 and 3 and Columbia

The participants have purchased all of 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 or not 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 subject to the requirements of the GASB Statement 68, Accounting and Financial Reporting for Pensions as of and for the fiscal year ended June 30, 2018 (in thousands):

Pension Liabilities	$	104,192
Pension Assets	$	-
Deferred Outflows of Resources	$	26,514
Deferred Inflows of Resources	$	21,673
Pension Expense	$	11,877

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 comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to:

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

Or the DRS CAFR 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 Energy Northwest 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 five years of service. Members retiring from inactive 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 non-duty 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 five 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, 2018:

PERS Plan 1 Actual Contribution Rates	Employer	Employee
PERS Plan 1	7.49%	6.00%
PERS Plan 1 UAAL	5.03%	
Administrative Fee	0.18%	
Total	12.70%	6.00%

Energy Northwest's actual contributions to the plan were $7,213 thousand for the fiscal year ended June 30, 2018.

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 five 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 non-duty 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 five years of eligible service. Plan 3 members are vested in the defined benefit portion of their plan after ten years of service; or after five 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 six 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, 2018:

PERS Plan 2/3 Actual Contribution Rates	Employer 2/3	Employee 2	Employee 3
PERS Plan 2/3	7.49%	7.38%	Varies
PERS Plan 1 UAAL	5.03%		
Administrative Fee	0.18%		
Total	12.70%	7.38%	Varies

Energy Northwest's actual contributions to the plan were $10,658 thousand for the fiscal year ended June 30, 2017.

Actuarial Assumptions

The total pension liability (TPL) for each of the DRS plans was determined using the actuarial valuation completed in 2017, with a valuation date of June 30, 2016. The actuarial assumptions used in the valuation were based on the results of the Office of the State Actuary's (OSA) 2007-2012 Experience Study and the 2015 Economic experience Study.

Additional assumptions for subsequent events and law changes are current as of the 2016 actuarial valuation report. The TPL was calculated as of the valuation date and rolled forward to the measurement date of June 30, 2017. Plan liabilities were rolled forward from June 30, 2016 to June 30, 2017, reflecting each plan's normal cost (using the entry-age cost method), assumed interest and actual benefit payments.

- **Inflation:** 3% total economic inflation; 3.75% salary inflation
- **Salary increases:** In addition to the base 3.75% salary inflation assumption, salaries are also expected to grow by promotions and longevity.
- **Investment rate of return:** 7.5%

Mortality rates were based on the RP-2000 report's Combined Healthy Table and Combined Disabled Table, published by the Society of Actuaries. The OSA applied offsets to the base table and recognized future improvements in mortality by projecting the mortality rates using 100% Scale BB. 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 changes in methods and assumptions in 2017 since the 2016 valuation.

- How terminated and vested member benefits are valued was corrected.
- How the basic minimum COLA in PERS Plan 1 is valued for legal order payees was improved.
- The average expected remaining service lives calculation was revised.

Discount Rate

The discount rate used to measure the total pension liability for all DRS plans was 7.5%.

To determine that rate, an asset sufficiency test included an assumed 7.7% long-term discount rate to determine funding liabilities for calculating future contribution rate requirements. Consistent with the long-term expected rate of return, a 7.5% future investment rate of return on invested assets was assumed for the test. Contributions from plan members and employers are assumed to continue being made at contractually required rates (including PERS 2/3 employers, whose rates include a component for the PERS 1 plan liabilities). Based on these 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 7.5% was used to determine the total liability.

Long-Term Expected Rate of Return

The long-term expected rate of return on the DRS pension plan investments of 7.5% was determined using a building-block-method. In selecting this assumption, the Office of the State Actuary (OSA) reviewed the historical experience date, 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 at 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, 2017:

Asset Class	Target Allocation	Percent Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.70%
Tangible Assets	5%	4.90%
Real Estate	15%	5.80%
Global Equity	37%	6.30%
Private Equity	23%	9.30%
Total	100%	

Sensitivity of NPL

The table below presents Energy Northwest's proportionate share of the net pension liability calculated using the discount rate of 7.5%, as well as what Energy Northwest's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1 percentage point lower (6.5%) or 1-percentage point higher (8.5%) than the current rate at June 30, 2018 (in thousands).

	1% Decrease (6.5%)	Current Discount Rate (7.5%)	1% Increase (8.5%)
PERS 1	$ 65,515	$ 53,781	$ 43,616
PERS 2/3	$ 135,814	$ 50,411	$ (19,563)

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, 2018 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	$ 51,420	$ 48,198	$ 99,618
Packwood	177	166	343
Business Development	1,576	1,477	3,053
Nine Canyon	457	429	886
Nuclear Project No. 1	151	141	292
Total	$ 53,781	$ 50,411	$ 104,192

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, 2018 Energy Northwest reported a total pension liability (asset) for its proportionate share of the net pension liabilities as follows (measured as of June 30, 2017 in thousands):

PERS 1	$ 53,781
PERS 2/3	50,411
Total	$ 104,192

Energy Northwest's proportionate share of the collective net pension liabilities was as follows:

	Proportionate Share 6/30/16	Proportionate Share 6/30/17	Change in Proportion
PERS 1	1.08%	1.13%	0.05%
PERS 2/3	1.38%	1.45%	0.07%

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.

The collective net pension liability (asset) was measured as of June 30, 2017, and the actuarial valuation date on which the total pension liability (asset) is based was as of June 30, 2016, with update procedures used to roll forward the total pension liability to the measurement date.

Pension Expense

For the fiscal year ended June 30, 2018, Energy Northwest's recognized pension expense as follows (in thousands):

PERS 1	$	5,922
PERS 2/3		5,712
Expenses		243
Total	$	11,877

Deferred Outflows of Resources and Deferred Inflows of Resources

At June 30, 2018, 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 of Actuarial Assumptions	-	-
Net Difference Between Projected and Actual Investment Earnings on Pension Plan Investments	-	2,007
Changes in Proportion and Differences Between Contributions and Proportionate Share of Contributions	-	-
Contributions Paid to PERS Subsequent to the Measurement Date	7,213	-
Total PERS 1	7,213	2,007
PERS 2/3:		
Differences Between Expected and Actual Economic Experience	5,108	1,658
Changes of Actuarial Assumptions	536	-
Net Difference Between Projected and Actual Investment Earnings on Pension Plan Investments	-	13,438
Changes in Proportion and Differences Between Contributions and Proportionate Share of Contributions	3,000	4,570
Contributions Paid to PERS Subsequent to the Measurement Date	10,657	-
Total PERS 2/3	19,301	19,666
Total All Plans	$ 26,514	$ 21,673

Deferred outflows of resources related to pensions resulting from Energy Northwest's contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability 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
2019	(1,357)	(6,650)
2020	428	(100)
2021	(99)	(1,195)
2022	(979)	(5,016)
2023	-	843
Thereafter	-	1,095
Total	$ (2,007)	$ (11,023)

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 2018 Energy Northwest contributed $3.6 million in employer matching funds while employees contributed $11.8 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, 2018.

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 $12.6 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 $127.3 million not including state insurance premium tax. Assessments are limited to $18.96 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.

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 - Asset Retirement Obligation (ARO)

Energy Northwest recognizes the fair value of a liability of an ARO for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets, such as nuclear decommissioning and site restoration liabilities, in the period in which it is incurred. Upon initial recognition of the AROs that are measurable, the probability weighted future cash flows for the associated retirement costs are discounted using a credit-adjusted-risk-free rate, and are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Capitalized asset retirement costs are depreciated over the life of the related asset with accretion of the ARO liability classified as an operating expense on the statement of revenues, expenses, and changes in net position each period. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss if the actual costs differ from the recorded amount. However, with regard to 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.

Energy Northwest has identified legal obligations to retire generating plant assets at the following business units: Columbia, Nuclear Project No. 1 and Nine Canyon. Decommissioning and site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the NRC regulations and 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)

As of June 30, 2018, Columbia has a capital decommissioning net asset value of zero and an accumulated liability of $161.2 million for the generating plant, and for the Independent Spent Fuel Storage Installation (ISFSI) a net asset value of $1.0 million and an accumulated liability of $2.6 million.

As of June 30, 2018, Nuclear Project No. 1 has a capital decommissioning net asset value of zero and an accumulated liability of $4.7 million.

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. As of June 30, 2018, Nine Canyon has a capital decommissioning net asset value of $0.4 million and an accumulated liability of $1.6 million.

Packwood's obligation has not been calculated because the time frame and extent of the obligation was considered under this statement as indeterminate. As a result, no reasonable estimate of the ARO obligation can be made. An ARO will be required to be recorded if circumstances change. Management believes that these assets will be used in utility operations for the foreseeable future.

The following table describes the changes to Energy Northwest's ARO liabilities for the year ended June 30, 2018. The balance is included in the accounts payable and accrued expense balances for each unit. ISFSI is included in Columbia's balance:

Asset Retirement Obligation (Dollars in thousands)

Columbia Generating Station		
Balance at Beginning of the Year	$	153,164
Current year accretion expense		8,010
ARO Ending Balance	$	161,174
ISFSI		
Balance at Beginning of the Year	$	2,525
Current year accretion expense		122
ARO Ending Balance	$	2,647
Nuclear Project No. 1		
Balance at Beginning of the Year	$	7,173
Current year accretion		(2,477)
ARO Ending Balance	$	4,696
Nine Canyon Wind Project		
Balance at Beginning of the Year	$	1,514
Current year accretion expense		62
ARO Ending Balance	$	1,576

Monies related to the ISFSI decommissioning trust are included in the decommissioning balance for Columbia.

NOTE 10 - Decommissioning and Site Restoration

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 (See Note 9). 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 2018. 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 December 2015.

Energy Northwest's estimate of Columbia's plant decommissioning costs in FY 2017 dollars is $490.2 million and estimate of Columbia's ISFSI decommissioning costs in FY 2015 dollars is $6.1 million. This estimate, which is updated biannually for the plant decommissioning and every three years for the ISFSI decommissioning with the last update for the plant decommissioning occurring in fiscal year 2018 and for the ISFSI in fiscal year 2015, is based on the NRC minimum amount (based on NRC 2016 study for the plant and NRC 2013 study for the ISFSI) required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

The fair value of cash and investment securities in the decommissioning and site restoration funds as of June 30, 2018, totaled approximately $290.5 million and $46.6 million, respectively. The fair value of cash and investment securities in the site restoration fund for Nuclear Project No. 1 is $30.3 million. Since September 1996, these 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 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.

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Beginning in FY 2003, an annual contribution is made to the Energy Northwest Decommissioning Fund. These contributions are held by Energy Northwest and not held in trust by BPA. The fair market value of cash and investments as of June 30, 2018, is $1.9 million. These contributions will occur through FY 2044; cash payments will begin for decommissioning and site restoration in FY 2045.

NOTE 11 - 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 2014.

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 $15,143,888.14 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 $7,200,184.33 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 confirmation that it would receive $11,139,344.69 in reimbursed costs in September 2018.

NOTE 12 - 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 third delivery of 150,000 SWU was received August 30, 2017 for $24.9 million. The total gain reported for the sale was $5.2 million reported on the Statements of Revenues, Expenses, and Changes in Net Position under Other. The remaining sales under this agreement are scheduled to take place between July 2018 and September 2022.

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 $86.0 million.

The current period operating expense for Columbia was $50.7 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 2018. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refueling. The FY2018 ISFSI loading campaign filled a total of 9 casks. The next ISFSI loading campaign is scheduled for March of 2022 for a total of 9 casks.

SCHEDULES OF REQUIRED SUPPLEMENTARY INFORMATION (Unaudited)

Schedule of the Energy Northwest's Proportionate Share of the Net Pension Liability (in thousands)

	PERS 1				
Measurement Date Ended June 30	2017	2016	2015	2014	2013
Proportion of the net pension liability (asset)	1.13%	1.08%	1.24%	1.22%	1.19%
Proportionate share of the net pension liability (asset)	$ 53,781	$ 58,147	$ 65,005	$ 61,291	$ 71,094
Covered-employee payroll	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	37.75%	45.09%	42.09%	42.39%	50.63%
Plan fiduciary net position as a percentage of the total pension liability	61.24%	57.03%	59.10%	61.19%	55.70%

	PERS 2/3				
Measurement Date Ended June 30	2017	2016	2015	2014	2013
Proportion of the net pension liability (asset)	1.45%	1.38%	1.60%	1.55%	1.55%
Proportionate share of the net pension liability (asset)	$ 50,411	$ 69,510	$ 57,017	$ 31,410	$ 66,351
Covered-employee payroll	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	35.47%	54.04%	37.00%	21.79%	47.52%
Plan fiduciary net position as a percentage of the total pension liability	90.97%	85.82%	89.20%	93.29%	84.60%

Schedule of Energy Northwest's Contributions (in thousands)

PERS 1

Fiscal Year Ended June 30	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Contractually Required Contribution	$ 7,213	$ 6,818	$ 6,141	$ 5,711	$ 5,385	$ 3,078	$ 70	$ 88	$ 104	$ 245
Contributions in Relation to the Contractually Required Contribution Subtotal	(7,213)	(6,818)	(6,141)	(5,711)	(5,385)	(3,078)	(70)	(88)	(104)	(245)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Covered-Employee Payroll	$ 143,282	$ 142,483	$ 128,944	$ 154,431	$ 144,597	$ 140,409	$ 996	$ 1,610	$ 1,933	$ 2,894
Contributions as a Percentage of Covered Employee Payroll	5.03%	4.79%	4.76%	3.70%	3.72%	2.19%	7.03%	5.47%	5.38%	8.47%

PERS 2/3

Fiscal year Ended June 30	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Contractually Required Contribution	$ 10,658	$ 8,862	$ 8,200	$ 7,108	$ 6,564	$ 6,020	$ 8,760	$ 6,533	$ 6,225	$ 9,522
Contributions in Relation to the Contractually Required Contribution	(10,658)	(8,862)	(8,200)	(7,108)	(6,564)	(6,020)	(8,760)	(6,533)	(6,225)	(9,522)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Covered-Employee Payroll	$ 143,015	$ 142,140	$ 128,634	$ 154,080	$ 144,158	$ 139,637	$ 134,777	$ 133,276	$ 123,367	$ 124,301
Contributions as a Percentage of Covered Employee Payroll	7.45%	6.23%	6.37%	4.61%	4.55%	4.31%	6.50%	4.90%	5.05%	7.66%

Notes to Schedules

Information is presented only for those years for which information is available.

There were no changes to any actuarial assumptions during fiscal year 2018.

*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).

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PROPOSED FORM OF OPINION OF BOND COUNSEL
FOR THE SERIES 2019-A/B BONDS

Energy Northwest

J.P. Morgan Securities LLC

Merrill Lynch, Pierce, Fenner & Smith Incorporated/BofA Securities, Inc.

Citigroup Global Markets Inc.

Wells Fargo Bank, National Association

Ladies and Gentlemen:

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 $251,575,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A and the $18,330,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-B (Taxable) (the "2019-A/B (Taxable) Bonds"). The 2019-A/B (Taxable) Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. 1042 (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on October 23, 1997, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 27, 2019 (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 2019-A/B (Taxable) Bonds are subject to redemption prior to their stated maturities as provided in the Bond Resolutions. The 2019-A/B (Taxable) 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 2019-A/B (Taxable) Bonds and apply the proceeds of the 2019-A/B (Taxable) 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 Resolution to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the 2019-A/B (Taxable) Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2019-A/B (Taxable) 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 2019-A/B (Taxable) Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2019-A/B (Taxable) 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 2019-A/B (Taxable) 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 PEPPER PLLC

PROPOSED FORM OF SUPPLEMENTAL OPINION OF BOND COUNSEL
FOR THE SERIES 2019-A/B BONDS

Energy Northwest

J.P. Morgan Securities LLC

Merrill Lynch, Pierce, Fenner & Smith Incorporated/BofA Securities, Inc.

Citigroup Global Markets Inc.

Wells Fargo Bank, National Association

Ladies and Gentlemen:

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 $251,575,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A and the $18,330,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-B (Taxable) (the "2019-A/B (Taxable) Bonds"). The 2019-A/B (Taxable) Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. 1042 (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on October 23, 1997, as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 27, 2019 (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 2019-A/B (Taxable) Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. 2 Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. 2 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 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 PEPPER PLLC

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL
FOR THE SERIES 2019-A/B BONDS

Energy Northwest
P.O. Box 968
Richland, Washington 99352

Energy Northwest
$251,575,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A
$18,330,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable)

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 $251,575,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2019-A (the "Series 2019-A Bonds"), and $18,330,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2019-B (Taxable) (the "Series 2019-B (Taxable) Bonds").

The Series 2019-A Bonds and the Series 2019-B (Taxable) 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 27, 2019 (the "Columbia Resolution"). The Columbia Resolution provides that the Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds are being issued for the purpose of financing certain additions and improvements to the Columbia Generating Station, refunding certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Series 2019-A Bonds and the Series 2019-B (Taxable) 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 Pepper PLLC, 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 2019-A Bonds (the "Prior Bond Counsel Opinions"), each of which speaks as of its dated date.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, 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 fourth 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 2019-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 2019-A Bonds, the Series 2019-B (Taxable) Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against 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 8, 2019, relating to the Series 2019-A Bonds and the Series 2019-B

(Taxable) Bonds, or other offering material relating to those Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds and express no opinion with respect thereto.

We have relied with your consent on the Bond Counsel Opinions with respect to the validity of the Series 2019-A Bonds and the Series 2019-B (Taxable) Bonds and with respect to the due authorization and issuance of the Series 2019-A Bonds and the Series 2019-B (Taxable) 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 2019-A Bonds and the Series 2019-B (Taxable) 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 2019-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 2019-A Bonds is not a specific preference item for purposes of the federal alternative minimum tax.

3. Interest on the Series 2019-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1986 Code or Section 103 of the 1954 Code.

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 2019-A Bonds or the Series 2019-B (Taxable) Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2019 BUDGETS

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Albion, Idaho	0.004	0.016	0.003
	Alder Mutual Light Company, Washington	0.002		
	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	0.025		
	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 (112)	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 2019 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 2019-A/B Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2019-A/B 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, and may be the Consulting Engineer appointed pursuant to Resolution No. 775.

"*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 act as securities depository for the Series 2019-A/B Bonds. The Series 2019-A/B Bonds will be issued as fully-registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Series 2019-A Bond certificate will be issued for each maturity of the Series 2019-A Bonds in the principal amount of such maturity and will be deposited with DTC. One fully-registered Series 2019-B (Taxable) Bond certificate will be issued for each maturity of the Series 2019-B (Taxable) 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. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, and 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 DTC 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 2019-A/B 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 2019-A/B Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2019-A/B Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Series 2019-A/B Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Series 2019-A/B Bonds, except in the event that use of the book entry-entry system for the Series 2019-A/B Bonds is discontinued.

To facilitate subsequent transfers, all Series 2019-A/B Bonds deposited by DTC 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 2019-A/B Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2019-A/B Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2019-A/B 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 shall be sent to DTC. If less than all of the Series 2019-A/B Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Series 2019-A/B Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to 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 2019-A/B 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 2019-A/B 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 DTC 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 DTC 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 2019-A/B Bonds at any time by giving reasonable notice to Energy Northwest and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2019-A/B Bond certificates are required to be printed and delivered.

Energy Northwest may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, Series 2019-A/B Bond certificates will be printed and delivered.

With respect to Series 2019-A/B Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Bond Registrar 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 2019-A/B Bonds with respect to, (i) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the Series 2019-A/B Bonds; (ii) the delivery to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any notice with respect to the Series 2019-A/B Bonds, including any notice of redemption; (iii) the payment to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the Series 2019-A/B Bonds; (iv) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the Series 2019-A/B Bonds; (v) any consent given action taken by DTC as registered owner; or (vi) any other matter. Energy Northwest and the Bond Registrar may treat and consider Cede & Co., in whose name each Series 2019-A/B Bond is registered on the Bond Register, as the holder and absolute owner of such Series 2019-A/B Bond for the purpose of payment of principal and interest with respect to such Series 2019-A/B Bond, for the purpose of giving notices of redemption and other matters with respect to such Series 2019-A/B Bond, for the purpose of registering transfers with respect to such Series 2019-A/B Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the DTC Participant acquires an interest in the Series 2019-A/B Bonds.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENT

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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of March 31, 2019" 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, 2019:

(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, 2019:

(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 2019-A/B 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 2019-A/B Bonds;

vii. Modifications to rights of Series 2019-A/B Bondholders, if material;

viii. Optional, contingent or unscheduled calls of any Series 2019-A/B 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 2019-A/B 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 2019-A/B Bonds, and (ii) reference to items (iv) and (v) above that no credit enhancements or liquidity facilities secure payment of the Series 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B 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 2019-A/B Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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ENERGY NORTHWEST • COLUMBIA GENERATING STATION ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2019-A AND ELECTRIC REVENUE REFUNDING BONDS, SERIES 2019-B (TAXABLE)

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