

NEW ISSUE

BOOK-ENTRY-ONLY

Interest on the Series 2017 Bonds is includible in gross income of the owners thereof for federal income tax purposes. In the opinion of Bond Counsel, interest on the Series 2017 Bonds is not subject to the income tax imposed by the State of Idaho under the Idaho Income Tax Act. See "TAX MATTERS" herein.

\$200,765,000
IDAHO ENERGY RESOURCES AUTHORITY
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1)
Series 2017 (Federally Taxable)

Dated: Date of Delivery

Due: September 1, as shown on inside cover

The Series 2017 Bonds will be special obligations of the Idaho Energy Resources Authority (the "Issuer") payable solely from the trust estate pledged therefor which trust estate includes amounts derived from lease rental payments paid to the Issuer pursuant to a Lease-Purchase Agreement between the Issuer and the United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

Bonneville's payments under the Lease-Purchase Agreement will be made solely from the Bonneville Fund. The Lease-Purchase Agreement provides that Bonneville's obligation to pay the lease rental payments and all amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project financed with the proceeds of the Series 2017 Bonds is operating or operable. Bonneville's payment obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America. See "THE ISSUER – Limited Obligations of the Issuer."

The Series 2017 Bonds are being issued for the principal purpose of acquiring certain transmission facilities to be leased by the Issuer to Bonneville. See "PURPOSE OF ISSUANCE AND USE OF PROCEEDS."

The Series 2017 Bonds will bear interest as shown on the inside cover, payable on March 1, 2018 and semi-annually thereafter on March 1 and September 1 of each year.

The Series 2017 Bonds will be issued in fully registered form and will be initially registered only in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"), which will act as securities depository for the Series 2017 Bonds. Individual purchases in principal amounts of \$5,000 or multiples thereof will be made only through the book-entry-only system maintained by DTC through brokers and dealers who are, or act through, DTC Participants. The purchasers of the Series 2017 Bonds will not receive certificates representing their interest in the Series 2017 Bonds. Ownership interests in the Series 2017 Bonds will be shown on, and transfers of Series 2017 Bonds will be effected only through, records maintained by DTC and its participants. Payments of principal of, premium, if any, and interest on the Series 2017 Bonds will be made to owners by DTC through its participants.

The Trustee for the Series 2017 Bonds is U.S. Bank National Association.

The Series 2017 Bonds are subject to redemption prior to maturity as described herein.

The Series 2017 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of the proceedings authorizing the Series 2017 Bonds by Chapman and Cutler LLP, and to certain other conditions. Certain legal matters will be passed upon for the Issuer by Williams & Bradbury, P.C., Boise, Idaho, and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York. The Series 2017 Bonds are expected to be delivered through the facilities of DTC on or about September 21, 2017.

BofA Merrill Lynch

Wells Fargo Securities

Citigroup

TD Securities

September 11, 2017

**MATURITIES, PRINCIPAL AMOUNTS,
INTEREST RATES AND PRICES
\$200,765,000**

<u>Year</u> <u>(September 1)</u>	<u>Principal</u> <u>Amount</u>	<u>Interest</u> <u>Rate</u>	<u>CUSIP[†]</u> <u>Number</u>
2023	\$25,765,000	2.297%	451174AA4
2024	30,000,000	2.447	451174AB2
2026	70,000,000	2.772	451174AC0
2028	75,000,000	2.952	451174AD8

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

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

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

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

The Issuer makes no representation as to the accuracy or completeness of any information in this Official Statement and takes no responsibility for its contents, other than the information relating to the Issuer under the headings “THE ISSUER” and “LEGALITY FOR INVESTMENT.”

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS WHICH STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE MARKET PRICE OF THE SERIES 2017 BONDS.

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

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OFFICIAL STATEMENT

\$200,765,000

**Idaho Energy Resources Authority
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1),
Series 2017 (Federally Taxable)**

INTRODUCTORY STATEMENT

This Official Statement provides information concerning the issuance by the Idaho Energy Resources Authority (the “Issuer”) of \$200,765,000 principal amount of its Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1), Series 2017 (Federally Taxable) (the “Series 2017 Bonds”). The Series 2017 Bonds are being issued to finance the costs of acquiring certain transmission facilities (the “Project”), as further described herein under “THE PROJECT,” to be owned by the Issuer and leased to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration (“Bonneville”).

The Issuer will execute a Lease-Purchase Agreement with Bonneville dated September 21, 2017 (the “Lease-Purchase Agreement”) pursuant to which the Issuer will lease the Project to Bonneville. The Series 2017 Bonds will be issued under an Indenture of Trust dated as of September 1, 2017 (the “Indenture”) between the Issuer and U.S. Bank National Association, as trustee (the “Trustee”). Under the Indenture, the Issuer will assign to the Trustee certain rights under the Lease-Purchase Agreement, including the right to receive lease rental payments from Bonneville in amounts at least sufficient to pay when due the principal of, and interest on, the Series 2017 Bonds.

Brief descriptions and summaries of the Series 2017 Bonds, the Lease-Purchase Agreement and the Indenture follow in this Official Statement. These descriptions and summaries do not purport to be complete and are subject to and qualified by reference to the provisions of the complete documents, copies of which are available at the offices of the Trustee at Global Corporate Trust Services, 555 SW Oak Street, PD-OR-P7TD, Portland, Oregon 97204. Appendices A and B to this Official Statement have been furnished by Bonneville and contain information concerning the business of Bonneville. Capitalized terms not otherwise defined herein shall have the meanings given to such terms in the Indenture.

THE ISSUER

Organization and Purpose

The Idaho Energy Resources Authority was organized in 2005 pursuant to the Idaho Energy Resources Authority Act, Title 67, Chapter 89, Idaho Code, as amended (the “Act”). The Issuer is an independent public body politic and corporate and a public instrumentality of the State of Idaho (the “State”). The purpose of the Issuer is to promote the development and financing of electric generation, transmission and distribution of facilities for the benefit of investor-owned, cooperative, federal, state and municipal utilities that provide electric service at wholesale or retail in the State (referred to in the Act as “participating utilities”), and to thereby promote and protect the economy of the State and the health, safety and welfare of its people.

Board of Directors

The Issuer is governed by a Board of Directors consisting of seven members appointed by the Governor and confirmed by the State Senate. Directors serve for staggered five-year terms and hold office until their successors are appointed. Directors may not serve for two consecutive terms. The following table lists the Directors and their terms in office:

NAME	TITLE	OCCUPATION	TERM BEGAN [*]	TERM ENDS [†]
Randolph J. Hill	Chairman	Corporate Lawyer, Stoel Rives; Director, U.S. Geothermal Inc.; Director, Andrus Center for Public Policy (Boise State University); Member, Energy Storage Task Force, Idaho Strategic Energy Alliance.	1/3/2013	6/30/2022
Michael P. Elliott	Director	Licensed professional engineer. Over 45 years of electrical engineering and consulting experience with national engineering and energy project development firms.	6/7/2017	7/1/2021
George Eskridge	Director	Retired; former Member, Idaho House of Representatives; former BPA Account Executive.	1/8/2015	6/30/2019
Jackie Flowers	Director	General Manager, Idaho Falls Power. Chair, Idaho Strategic Energy Alliance.	9/4/2013	6/30/2018
Daniel Kunz	Director	Chairman and CEO, Gold Torrent Inc.	9/4/2013	6/30/2018
Mark Lliteras	Director	Retired; former Executive Vice President, Wells Fargo Bank.	7/1/2016	6/30/2021
Mike Mooney	Director	Retired; former Regional President, Bank of the Cascades.	2/18/2016	6/30/2020

Management and Administration

The Interim Executive Director of the Issuer is Ronald L. Williams. He was appointed to that position in May 2017. Mr. Williams also serves as general counsel to the Issuer. Mr. Williams' legal practice focuses on energy, telecommunications and business law, as well as legislative and regulatory matters. He is a graduate of the University of Idaho and the Northwestern School of Law at Lewis and Clark College, Portland, Oregon, and is licensed to practice law in Idaho and Oregon.

The Issuer's offices are located at 802 West Bannock Street, Suite 900, Boise, Idaho 83702, and the Authority's mailing address is P.O. Box 1531, Boise, Idaho 83701.

Powers of the Issuer

Under the Act, the Issuer has the power, among others, to (i) acquire and construct facilities, (ii) issue bonds to finance the cost and acquisition of facilities, (iii) sell or lease facilities to participating utilities, and (iv) enter into trust indentures and other instruments to secure its bonds. The Act provides that the Issuer shall not commence the development or financing for any facility until it shall have entered into contractual arrangements with a participating utility that contain provisions determined by the Issuer to provide adequate assurance that all capital, operating and related costs of the facility will be paid or provided for by the participating utility.

The Act provides that (i) for so long as any bonds are outstanding or any contract, agreement or transaction between the Issuer and a participating utility is in effect, the Issuer shall not have the power and shall not be authorized to be a debtor under the U.S. Bankruptcy Code or any other bankruptcy, insolvency, moratorium, liquidation, dissolution or wind-down law, and (ii) upon the payment in full of bonds issued to finance a facility, the Issuer will convey title to the facility to the participating utility, and may pledge and assign its interest in the facility to the participating utility to secure its obligation to convey title. The Issuer has pledged and assigned its interest in

^{*} Date of Director's appointment by the Governor.

[†] Directors hold office until their successors have been appointed and qualified. On June 7, 2017, Mr. Hill was reappointed by the Governor to a second term ending on June 30, 2022; his reappointment is subject to confirmation by the Idaho Senate at its 2018 general session. On June 7, 2017, Mr. Elliott was appointed by the Governor to serve the remaining term of a former director.

the Project to secure its obligation to convey title to the Project to Bonneville upon the full and final payment of the Bonds.

The Issuer may from time to time issue bonds, notes and other obligations to finance electric facilities for the benefit of other participating utilities. Any such obligations will be issued pursuant to instruments separate and apart from the Indenture and will be payable from rents, fees and other payments that are separate and apart from the rents, fees and other payments that the Issuer has pledged to the payment of the Series 2017 Bonds.

Limited Obligations of the Issuer

The Series 2017 Bonds shall not be payable out of any funds of the Issuer other than those pledged therefor but shall be payable by the Issuer solely from the Trust Estate. Nothing in the Series 2017 Bonds, in the Lease-Purchase Agreement or in the Indenture or any other agreement or binding document shall be considered as pledging any other funds or assets of the Issuer. All right, title, and interest of the Issuer in and to the Trust Estate shall be pledged to the Trustee for the benefit of Series 2017 Bondholders for the payment of the principal of, premium, if any, and interest on the Series 2017 Bonds in accordance with their terms and provisions of the Indenture. THE SERIES 2017 BONDS ARE NOT AN INDEBTEDNESS, DEBT OR LIABILITY OF THE STATE OR ANY AGENCY OR SUBDIVISION OF THE STATE, AND NONE OF THE STATE, ITS AGENCIES OR SUBDIVISIONS SHALL BE LIABLE ON THE SERIES 2017 BONDS. THE SERIES 2017 BONDS DO NOT CONSTITUTE THE GIVING, PLEDGING OR LOANING OF THE FAITH AND CREDIT OF THE STATE OR ITS AGENCIES OR SUBDIVISIONS. THE SERIES 2017 BONDS DO NOT DIRECTLY, INDIRECTLY OR CONTINGENTLY, OBLIGATE THE STATE OR ANY AGENCY OR SUBDIVISION OF THE STATE TO LEVY OR COLLECT ANY FORM OF TAXES OR ASSESSMENTS FOR THEIR PAYMENT OR TO CREATE ANY INDEBTEDNESS PAYABLE OUT OF TAXES OR ASSESSMENTS. THE ISSUER HAS NO POWER TO LEVY OR COLLECT TAXES OR ASSESSMENTS.

PURPOSE OF ISSUANCE AND USE OF PROCEEDS

Pursuant to a lease-purchase agreement and a related construction agreement dated as of January 17, 2012, between Bonneville and the Northwest Infrastructure Financing Corporation VI ("NIFC VI"), NIFC VI provided for the acquisition, construction, installation and equipping of certain transmission facilities (as described below, the "Project") and leased the Project to Bonneville. NIFC VI financed such acquisition, construction, installation and equipping through a credit agreement with Bank of America, N.A., and secured its obligations under such credit agreement with the lease-purchase agreement by and between NIFC VI, as lessor, and Bonneville, as lessee, and the payments from Bonneville thereunder.

The proceeds from the sale of the Series 2017 Bonds will be used by the Issuer to acquire the Project from NIFC VI. NIFC VI will use the funds received from the Issuer to pay the indebtedness incurred under said credit agreement. Upon receipt of the acquisition payment, NIFC VI will relinquish all of its rights and interests in the Project and irrevocably transfer such rights and interests to the Issuer. The proceeds from the sale of the Series 2017 Bonds will also be used by the Issuer to pay the costs of issuance of the Series 2017 Bonds (including Underwriters' discount) and certain administrative costs of the Issuer. The costs of issuance and such administrative costs are \$1,455,405.37.

THE PROJECT

As described herein under "THE LEASE-PURCHASE AGREEMENT," the Project will be leased by the Issuer to the United States Department of Energy, acting by and through the Administrator of the Bonneville Power Administration. The Project consists of electric transmission system facilities located in the Pacific Northwest region of the United States. The Project includes: (i) twelve reconfigured or rebuilt Federal Columbia River Power System transmission lines, including airway lighting, cable, conductor, disconnect switches, grounding systems, insulators, jumper string assemblies, overhead ground wire, surge arresters, steel towers, steel poles, or wood poles; and (ii) additions or replacements at thirty-five Federal Columbia River Power System converter stations, radio stations, or substations, including aluminum bus, batteries with chargers and racks, circuit switchers, control houses, control systems, current transformers, current limiting reactors, disconnect switches, engine generators, fabric fences and gates, fiber optic cable with vaults, grounding systems, insulators, metering packages, oil spill containment systems

and storage tanks, overhead ground wire, overhead ground wire poles, power circuit breakers, power transformers, radio station buildings, relay packages and relay racks, remedial action scheme systems, seismic jumper assemblies, sequential event recorder systems, shunt capacitors, shunt reactors, station service transformers, steel poles, steel towers and tower bridges, supervisory control and acquisition data systems, surge arresters, switchyard lighting, transfer switches, transfer trip systems, voltage transformers, or wood poles. These additions, replacements, and improvements were acquired, constructed, installed or equipped for the purpose of maintaining system reliability and providing enhanced electric transmission service. Bonneville's leasehold interests in the Project and its rights and obligations in connection therewith are a part of the "Federal Transmission System" as described in Bonneville's organic statutes. Bonneville has obtained and holds, in the name of the United States of America, all of the rights of way and other real property interests on which the Project is sited. These real property interests are not subject to condemnation by any state or local authority.

Under the Lease-Purchase Agreement and the Indenture, the definition of the Project may be amended from time to time without the consent of the holders of the Series 2017 Bonds; provided, however, that a change in the definition of the Project shall not entitle Bonneville to any abatement or reduction in the lease rental payments under the Lease-Purchase Agreement. See "THE LEASE-PURCHASE AGREEMENT - Changing the Definition of the Project."

The Series 2017 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described under "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2017 BONDS – Trust Estate." Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2017 Bonds.

SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2017 BONDS

Trust Estate

Under the terms of the Indenture, the Series 2017 Bonds are payable solely but equally and ratably from and are secured solely but equally and ratably by the Trust Estate which consists of (i) all right, title and interest of the Issuer in and to the Lease-Purchase Agreement, including all lease rental payments, revenues and receipts payable or receivable thereunder, excluding, however, the Issuer's Reserved Rights, which rights may be enforced by the Issuer and the Trustee jointly or severally; (ii) all right, title and interest of the Issuer in and to the Project, subject to the Lease-Purchase Agreement and Permitted Encumbrances; (iii) all moneys and securities from time to time held by the Trustee under the terms of the Indenture including amounts set apart and transferred to the Project Fund, the Bond Fund or the Reserve Fund, and all investment earnings of any of the foregoing, subject to disbursements from the Project Fund, the Bond Fund, or the Reserve Fund in accordance with the provisions of the Lease-Purchase Agreement and the Indenture; (iv) any and all other property of every kind and nature from time to time which was heretofore or will be hereafter by delivery or by writing of any kind conveyed, mortgaged, pledged, assigned or transferred, as and for additional security under the Indenture, by the Issuer or by any other person, firm or corporation with or without the consent of the Issuer, to the Trustee which is hereby authorized to receive any and all such property at any time and at all times to hold and apply the same subject to the terms of the Indenture.

Pursuant to the Lease-Purchase Agreement between Bonneville and the Issuer, Bonneville is required to make lease rental payments in the amounts set forth in schedules contained in the Lease-Purchase Agreement which schedules will provide for lease rental payments at times and in amounts more than sufficient to pay the principal of and interest and all other amounts due on the Series 2017 Bonds. See herein "THE LEASE-PURCHASE AGREEMENT" and "THE INDENTURE." Such lease rental payments are irrevocably pledged by the Issuer pursuant to the Indenture for the payment of principal or redemption premium, if any, of and interest on the Series 2017 Bonds. The Lease-Purchase Agreement provides that such lease rental payments will be made directly to the Trustee for deposit in the Bond Fund.

The Lease-Purchase Agreement provides that Bonneville's obligation to pay the lease rental payments and all other amounts payable under the Lease-Purchase Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project is operating or operable. Bonneville's obligation to make the lease rental payments will continue until September 1, 2028, unless sooner terminated or extended in accordance with the provisions of the Lease-Purchase Agreement, and is coterminous with the final

maturity of the Series 2017 Bonds. **Bonneville’s obligations under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States of America nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.**

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease-Purchase Agreement. The Issuer and Bonneville will declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer will waive any rights it may have as a secured party with respect to the Project. The Series 2017 Bonds will not be secured by a mortgage or other lien on the Project and the interest of the Issuer in the Project is limited by the Lease-Purchase Agreement as described above. Therefore, the Bondholders should not look to the Project as providing any security for the payment of the Series 2017 Bonds. See “THE PROJECT.”

Source of Bonneville’s Payments: The Bonneville Fund

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

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

Payments by Bonneville under the Lease-Purchase Agreement are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations or the Series 2017 Bonds intended to be or are they secured by the full faith and credit of the United States of America.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are to be made from net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal Columbia River Power System (the “Federal System”), other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the United States Corps of Engineers and the United States Bureau of Reclamation for certain costs allocated to electric power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2016 payment responsibility to the United States Treasury in full and on time for the 33rd consecutive year.

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

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its scheduled payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to

receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has not deferred such payments since 1983.

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

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

Bonneville has substantial outstanding repayment obligations to the United States Treasury ("Federal Debt") and for debt issued by third parties (and similar obligations), the repayment of which is secured by Bonneville financial commitments ("Non-Federal Debt"). Non-Federal Debt includes lease-purchase agreements, net billing agreements, and other obligations. As of September 30, 2016, aggregate debt outstanding was approximately \$15.6 billion, about half of which relates to outstanding Non-Federal Debt. For further information on Non-Federal Debt, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt."

Covenants

Non-Impairment. Under State law, the State has pledged to and agreed with the holders of the Series 2017 Bonds, the Trustee and Bonneville that the State will not limit, alter, restrict or impair the rights of the Issuer pursuant to the Act (1) to acquire, construct, reconstruct, maintain and operate the Project, (2) to establish, revise, charge and collect rates, rents, fees and other charges as may be convenient or necessary to produce sufficient revenues to meet the expenses of maintenance and operation thereof, and (3) to fulfill the terms of any agreements made with the holders of the Series 2017 Bonds, and with the Trustee and Bonneville (as parties who have contracted with the Issuer pursuant to the Act), or in any way impair the rights or remedies of the holders of the

Series 2017 Bonds or of such parties until the Series 2017 Bonds, together with the interest thereon, are fully paid and discharged and such contracts are fully performed on the part of the Issuer.

No Bankruptcy. State law specifically prohibits the Issuer from becoming a debtor under the U.S. bankruptcy code, title 11 U.S.C., or any other bankruptcy, insolvency, moratorium, liquidation, dissolution or wind-down law for so long as the Series 2017 Bonds are outstanding or any contract, agreement or transaction between the Issuer and a “participating utility” as defined in the Act is in effect.

THE SERIES 2017 BONDS

General

The Series 2017 Bonds will be issued originally as a single global certificate for each maturity registered to DTC, or its nominee, Cede & Co., to be held in DTC’s book-entry-only system. So long as the Series 2017 Bonds are held in the book-entry-only system, DTC (or a successor securities depository) or its nominee will be the registered owner of the Series 2017 Bonds for all purposes of the Indenture, the Series 2017 Bonds and this Official Statement. Interest on the Series 2017 Bonds will be payable only through participants or indirect participants in DTC so long as the Series 2017 Bonds are held in the book-entry-only system. The Series 2017 Bonds are available to the ultimate purchasers in book-entry form only, in denominations of \$5,000 and integral multiples thereof. See “Book-Entry-Only System” below.

The Series 2017 Bonds are dated the date of their delivery, and mature on September 1 in the years and in the principal amounts shown on the inside cover page of this Official Statement. The Series 2017 Bonds will bear interest, computed on the basis of a 360-day year of twelve 30-day months, at the rates shown on the inside cover page of this Official Statement. The Series 2017 Bonds are subject to redemption prior to maturity as set forth below. Additional Bonds may be issued under the Indenture. Such Bonds, together with the Series 2017 Bonds, are referred to as the “Bonds.”

Interest on the Series 2017 Bonds will be payable on March 1 and September 1 of each year, commencing March 1, 2018, to the persons in whose name the Series 2017 Bonds are registered on the fifteenth day of the month preceding the interest payment date; provided that overdue interest shall be paid to the persons in whose name such Series 2017 Bonds are registered by close of business on the fifth Business Day next preceding the date of payment of the defaulted interest. So long as the Series 2017 Bonds are held in the book-entry-only system, all payments of principal of and premium, if any, and interest are required to be made by the Trustee to DTC in immediately available funds for further distribution to beneficial owners of the Series 2017 Bonds.

Book-Entry-Only System

DTC will act as securities depository for the Series 2017 Bonds. The Series 2017 Bonds will be issued as fully-registered Series 2017 Bonds registered in the name of Cede & Co. (DTC’s partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Series 2017 Bond will be issued for the Series 2017 Bonds for each maturity, in the aggregate 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, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly (“Indirect Participants”). The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission (“SEC”). More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Series 2017 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2017 Bonds on DTC’s records. The ownership interest of each actual purchaser of each Series 2017 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 2017 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 2017 Bonds, except in the event that use of the book-entry-only system for the Series 2017 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2017 Bonds deposited by Direct Participants with DTC are registered in the name of DTC’s partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of the Series 2017 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not affect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2017 Bonds; DTC’s records reflect only the identity of the Direct Participants to whose accounts such Series 2017 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Series 2017 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the Series 2017 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2017 Bond documents. For example, Beneficial Owners of Series 2017 Bonds may wish to ascertain that the nominee holding the Series 2017 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the Trustee and request that copies of notices be provided directly to them. **THE ISSUER, BONNEVILLE AND THE TRUSTEE WILL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT AND INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO THE SERIES 2017 BONDS.**

Redemption notices will be sent to DTC. If less than all of the Series 2017 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 2017 Bonds unless authorized by a Direct Participant in accordance with DTC’s MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.’s consenting or voting rights to those Direct Participants to whose accounts the Series 2017 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Series 2017 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC’s practice is to credit Direct Participants’ accounts upon DTC’s receipt of funds and corresponding detail information from the Issuer or the Trustee, on payable dates in accordance with their respective holdings shown on DTC’s records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case

with securities held for the accounts of customers in bearer form or registered in “street name,” and will be the responsibility of such Participant and not of DTC, the Trustee, or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the Series 2017 Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2017 Bonds are required to be printed and delivered as described in the Indenture.

The Issuer, at the direction of Bonneville, may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, Series 2017 Bond certificates will be printed and delivered to DTC.

THE ISSUER, THE TRUSTEE, BONNEVILLE AND THE UNDERWRITERS SHALL NOT HAVE ANY RESPONSIBILITY OR OBLIGATION TO ANY DIRECT OR INDIRECT PARTICIPANT, ANY BENEFICIAL OWNER OR ANY OTHER PERSON CLAIMING A BENEFICIAL OWNERSHIP INTEREST IN THE SERIES 2017 BONDS UNDER OR THROUGH DTC OR ANY DTC PARTICIPANT, OR ANY OTHER PERSON WHICH IS NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A HOLDER, WITH RESPECT TO THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT; THE PAYMENT BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF ANY AMOUNT IN RESPECT OF THE PRINCIPAL OF, PREMIUM, IF ANY, OR INTEREST ON THE SERIES 2017 BONDS; ANY NOTICE WHICH IS PERMITTED OR REQUIRED TO BE GIVEN TO OWNERS UNDER THE INDENTURE; THE SELECTION BY DTC OR ANY DIRECT OR INDIRECT PARTICIPANT OF ANY PERSON TO RECEIVE PAYMENT IN THE EVENT OF A PARTIAL REDEMPTION OF THE SERIES 2017 BONDS; ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS AN OWNER; OR ANY OTHER PROCEDURES OR OBLIGATIONS OF DTC UNDER THE BOOK-ENTRY-ONLY SYSTEM.

SO LONG AS CEDE & CO. (OR SUCH OTHER NOMINEE AS MAY BE REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC) IS THE REGISTERED OWNER OF THE SERIES 2017 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS OR OWNERS OR REGISTERED HOLDERS OR REGISTERED OWNERS OF THE SERIES 2017 BONDS MEANS CEDE & CO., AS AFORESAID, AND DOES NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2017 BONDS.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2017 Bonds, payment of principal, interest and other payments on the Series 2017 Bonds to Direct and Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Series 2017 Bonds and other related transactions by and between DTC, the Direct and Indirect Participants and the Beneficial Owners is based solely on information provided by DTC. Accordingly, no representations can be made concerning these matters, and neither the Direct nor Indirect Participants nor the Beneficial Owners should rely on the foregoing information with respect to such matters, but should instead confirm the same with DTC.

Optional Redemption

The Series 2017 Bonds are subject to redemption prior to their respective maturities at the option of the Issuer (with the approval of Bonneville), in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The “Make-Whole Redemption Price” is the greater of (i) the issue price of the Series 2017 Bonds as shown on the cover page of this Official Statement (but not less than 100% of the principal amount of the Series 2017 Bonds to be redeemed), or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2017 Bonds to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2017 Bonds are to be redeemed, discounted to the date on

which such Series 2017 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 15 basis points, plus accrued and unpaid interest on the Series 2017 Bonds to be redeemed on the redemption date.

“Treasury Rate” means, with respect to any redemption date for a particular Series 2017 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 redemption date for a particular Series 2017 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 2017 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 2017 Bonds to be redeemed.

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

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

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

“Reference Treasury Dealer Quotations” means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2017 Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Issuer, the Trustee and Bonneville by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

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

Partial Redemption

If less than all of the Series 2017 Bonds are to be redeemed, the Issuer may select the maturity or maturities to be redeemed. The Indenture provides that the portion of any Series 2017 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 2017 Bonds for redemption, the Trustee will treat each such Series 2017 Bonds as representing that number of such Series 2017 Bonds of \$5,000 denomination that is obtained by dividing the principal amount of such Series 2017 Bonds to be redeemed in part by \$5,000.

The particular Series 2017 Bonds to be redeemed shall be determined by the Trustee, using such method as it shall deem fair and appropriate. If the Series 2017 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 2017 Bonds, if less than all of a maturity of the Series 2017 Bonds of a maturity are called for redemption, the particular Series 2017 Bonds or portions thereof to be redeemed shall be selected on a pro rata pass-through distribution of principal basis in

accordance with DTC procedures, or such other method as is in accordance with the operational arrangements of DTC then in effect. It is the Issuer's intent that redemption allocations made by DTC, the DTC Participants or such other intermediaries that may exist between the Issuer and the Beneficial Owners be made in accordance with the pro rata pass-through distribution of principal basis described below. However, the Issuer can provide no assurance that DTC, the DTC Participants or any other intermediaries will allocate redemptions among registered owners on such basis. If the DTC operational arrangements do not allow for the redemption of the Series 2017 Bonds on a pro rata pass-through distribution of principal basis as discussed above, then the Series 2017 Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

If the Series 2017 Bonds are not registered in book-entry-only form, any redemption of less than all of a maturity of the Series 2017 Bonds shall be allocated among the registered owners of such Series 2017 Bonds as nearly as practicable in proportion to the principal amounts of the Series 2017 Bonds owned by each registered owner, subject to the authorized denominations applicable to the Series 2017 Bonds. This will be calculated based on the following formula:

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

Notice of Redemption

Notice of redemption of any Series 2017 Bonds is to be given by the Trustee by first-class mail not less than 20 days (or such later date as may be permitted by DTC and the Trustee) nor more than 60 days before the redemption date to the registered owners of the Series 2017 Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2017 Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2017 Bonds which are to be redeemed, whether or not such notice is actually received. Failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the Series 2017 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2017 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 2017 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such Series 2017 Bonds on the redemption date and the Series 2017 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. The Issuer may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation, prior to the date scheduled for such redemption, to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry-only system is in effect with respect to the Series 2017 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2017 Bonds of a maturity are to be redeemed, DTC or its successor and Participants and Indirect Participants (as such terms are defined herein under the heading "THE SERIES 2017 BONDS – Book-Entry-Only System") will determine the particular ownership interests of Series 2017 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 2017 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2017 Bonds.

Neither the Issuer, the Trustee, nor the Underwriters can give any assurance that DTC, the Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2017 Bonds, or that they will do so on a timely basis.

THE LEASE-PURCHASE AGREEMENT

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

Lease Rental Payments

Bonneville agrees under the Lease-Purchase Agreement to pay to the Trustee lease rental payments for deposit in the Bond Fund created under the Indenture in the amounts set forth in schedules to the Lease-Purchase Agreement, which schedules provide for lease rental payments more than sufficient for the payment of the principal of, and interest on, the Series 2017 Bonds. The obligation of Bonneville to make all payments provided in the Lease-Purchase Agreement is stated to be absolute and unconditional, without any set-off or counterclaim. See “SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2017 BONDS” herein.

Bonneville has also agreed to pay, as additional rent under the Lease-Purchase Agreement, all Impositions, which are defined as all taxes and assessments, general and specific, if any, levied and assessed upon or against the Project, the Lease-Purchase Agreement, any estate or interest of the Issuer or Bonneville in the Project or transfer of such estate or interest, or the lease rental payments under the Lease-Purchase Agreement during the term of the Lease-Purchase Agreement, and all assessments and other governmental charges and impositions whatsoever, foreseen or unforeseen, ordinary or extraordinary, under any present or future law, and charges for public or private utilities or other charges incurred in the occupancy, use, operation, maintenance or upkeep of the Project.

Indemnity

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

Operation of the Project

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

Covenants

In the Lease-Purchase Agreement, Bonneville agrees, among other things, to pay all costs of maintaining the Project in the same manner in which Bonneville maintains similar facilities that it owns; to keep the Project free of liens, except as provided in the Lease-Purchase Agreement; to pay charges and assessments against the Project; to comply with law; to indemnify the Issuer and pay its fees and expenses as well as those of the Trustee; to furnish to

the Trustee, any requesting holder of more than \$1,000,000 of Series 2017 Bonds, and the Issuer, a copy of its financial statements, and to notify the Issuer and the Trustee of the occurrence of any Event of Default under the Lease-Purchase Agreement. See also “Continuing Disclosure” herein.

Damage, Destruction and Condemnation

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

Termination of the Lease-Purchase Agreement

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

Defaults

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

- (a) Failure by Bonneville to pay when due any rental payment that has become due and payable under the Lease-Purchase Agreement; and
- (b) Failure of Bonneville to pay any amount due under the Lease-Purchase Agreement (other than under paragraph (a) above) and continuance of such failure for thirty (30) days after notice of such failure is given to Bonneville by the Issuer or the Trustee.

Remedies

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

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

The Issuer, during the term of the Lease-Purchase Agreement, waives any and all rights as owner or as lessor of the Project to re-enter and take possession of the Project, to sublease the Project, to terminate the Lease-Purchase Agreement and to exclude Bonneville from possession of the Project upon the occurrence of an event of

default under the Lease-Purchase Agreement. The Issuer and Bonneville declare that the Lease-Purchase Agreement does not create a security interest in the Project in favor of the Issuer and the Issuer waives any rights it may have as a secured party with respect to the Project.

Statutory Limitation on Legal Remedies against Bonneville

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

Options

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

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

Force Majeure

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

Assignment or Sublease

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

Amendment

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

Changing the Definition of the Project

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

More particularly, the Issuer will commit to agree that, at the request of Bonneville, it will amend the definition of a Project (i) to change the location of the Project or any component or portion thereof, (ii) to remove any part of the Project, or (iii) to replace all or any part of such Project with one or more transmission facilities having a comparable value. The Project definition may be otherwise amended as may be agreed to by the Issuer and Bonneville. The amendment of the Project definition shall not entitle Bonneville to any abatement or reduction in the rentals and other amounts payable by Bonneville under the Lease-Purchase Agreement. In the event of a re-definition of the Project, there is no obligation or special right to call any of the Series 2017 Bonds prior to their final maturity. The right of Issuer and Bonneville to change the definition of the Project is separate and apart from the amendment of the Lease-Purchase Agreement. See "THE LEASE-PURCHASE AGREEMENT - Amendment," and "THE INDENTURE - Amendment of the Lease-Purchase Agreement."

If a portion of the Project becomes obsolete, worn-out, or otherwise is taken out of service or retired prior to the final maturity of the Series 2017 Bonds, the Project may be re-defined to remove such portions of the Project through an amendment to the definition of the Project. See "Sale, Assignment, or Other Dispositions of Portions of the Project" below. If such portion of the Project is replaced, the facilities so replacing the portion may be owned by Bonneville or another project owner or replaced with funds obtained by the Issuer under a lease with Bonneville separate and apart from the Lease-Purchase Agreement. See "THE PROJECT."

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

As described above, the definition of the Project may be amended from time to time to remove of any part of the Project. See "Changing the Definition of the Project" above. Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is obsolete, worn-out or no longer usable for the

purpose for which such portion had originally been acquired and Bonneville shall not be required to deposit in the Bond Fund or otherwise pay to the Issuer any amounts received by Bonneville from such sale, assignment or disposition. When removing any part of the Project which is obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired, Bonneville may notify Issuer that such portion no longer constitutes part of the Project and effective upon such notice the definition of the Project will be deemed so amended (the removal may also be effected through an amendment). Bonneville may remove from the Project and sell, assign or otherwise dispose of any portion of the Project which is not obsolete, worn-out or no longer usable for the purpose for which such portion had originally been acquired and the funds received from such sale, assignment or disposition shall be paid over to the Bond Fund to be applied to the payment of principal of, and interest and premiums, if any, on, the Series 2017 Bonds, and to the extent the amounts are so applied, they will constitute a contribution to lease rental payments otherwise payable by Bonneville.

THE INDENTURE

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

Trust Estate

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

Project Fund

The proceeds of the sale of the Series 2017 Bonds will be deposited in the Project Fund to be held by the Trustee. Moneys in the Project Fund will be applied to finance the acquisition of the Project from NIFC VI, and to pay expenses incurred in connection with the issuance and sale of the Series 2017 Bonds, and for other costs of the Project upon requisitions signed by an authorized representative of Bonneville or, with respect to certain costs of issuance, an authorized representative of the Issuer.

Bond Fund

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

Reserve Fund

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

Investments

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

Additional Bonds

So long as the Lease-Purchase Agreement is in effect, Additional Bonds may be issued under the Indenture from time to time in the discretion of the Issuer for the purpose of (i) providing funds to repair, relocate, replace, rebuild or restore the Project in the event of damage, destruction or taking by eminent domain, (ii) providing extensions, additions or improvements to the Project, or (iii) refunding outstanding Bonds. It is a condition to the issuance of Additional Bonds that the amounts payable by Bonneville under the Lease-Purchase Agreement will be adjusted to provide for the payment of principal of, premium, if any, and interest on the Additional Bonds. Additional Bonds shall be equally and ratably secured under the Indenture with the Series 2017 Bonds.

Events of Default and Remedies

Each of the following is an “Event of Default” under the Indenture:

- (a) failure in the payment of interest on any Bond when due;
- (b) failure in the payment of the principal or redemption premium, if any, of, or sinking fund installment for, any Bond when due, whether at the stated maturity thereof, upon any proceedings for redemption thereof or otherwise;
- (c) failure by the Issuer to perform or observe any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds (except as set forth in (a) or (b) above), and the continuance thereof for a period of thirty days after written notice to the Issuer and Bonneville from the Trustee or the holders of more than 25% of the aggregate principal amount of Bonds then outstanding; provided that, if the default can be remedied but not within the applicable period, the Issuer or Bonneville proceeds with diligence to cure the default, it shall not be an Event of Default; or
- (d) an Event of Default under the Lease-Purchase Agreement.

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

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

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

No holder of any Bond shall have any right to institute any suit, action or proceeding in equity or at law for the enforcement of the Indenture or for the execution of any trust thereof or any remedy under the Indenture, unless the Trustee has been notified of the default, and the holders of over 25% of aggregate principal amount of Bonds then outstanding have made a written request to the Trustee and have offered reasonable opportunity either to exercise the powers granted in the Indenture or to institute such action, suit or proceeding in its own name, and unless they also have offered to the Trustee adequate security and indemnity and the Trustee refuses to comply within 60 days. Nothing in the Indenture shall, however, affect or impair the right of any Bondholder to payment of

the principal or redemption price, if applicable, of, sinking fund installments for, and interest on any Bond at and after the maturity thereof, or the obligation of the Issuer to pay the principal or redemption price, if applicable, of, sinking fund installments for, and interest on the Bonds to the respective holders thereof at the time, place, from the source and in the manner expressed in the Bonds and the Indenture.

Waivers of Events of Default

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

Application of Moneys after Default

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

Amendments of the Indenture

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

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

for consent to such supplemental indenture, or (v) a modification, amendment or deletion with respect to any of the terms set forth above, without, in the case of items (ii) through (v) above, the written consent of 100% of the holders of the outstanding Bonds.

Amendment of the Lease-Purchase Agreement

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

Discharge of the Indenture

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

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

State Pledge

Pursuant to the Act, the State will pledge in the Indenture and agree with the holders of any Series 2017 Bonds, and with the Trustee and Bonneville, that the State will not limit, alter, restrict or impair the rights vested in the Issuer to acquire, construct, reconstruct, maintain and operate the Project or to establish, revise, charge and collect rates, rents, fees and other charges as may be convenient or necessary to produce sufficient revenues to meet the expenses of maintenance and operation thereof and to fulfill the terms of any agreements made with the holders of Bonds, and with the Trustee and Bonneville, or in any way impair the rights or remedies of the holders of the Series 2017 Bonds or of the Trustee and Bonneville until the Series 2017 Bonds, together with the interest thereon, are fully paid and discharged and such contracts are fully performed on the part of the Issuer.

CONTINUING DISCLOSURE

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

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

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

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended (“ERISA”), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the “Plans”) and persons who, with respect to a Plan, are fiduciaries or other “parties in interest” within the meaning of ERISA or “disqualified persons” within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2017 Bonds.

RATINGS

Moody’s Investors Service (“Moody’s”) and Fitch Ratings (“Fitch”) have assigned the Series 2017 Bonds the ratings of Aa1 / Stable Outlook and AA / Negative Outlook, respectively. Ratings were applied for by Bonneville and certain information was supplied by Bonneville to such rating agencies to be considered in evaluating the Series 2017 Bonds. Such ratings reflect only the respective views of such rating agencies, and an explanation of the significance of such ratings may be obtained only from the rating agency furnishing the same. There is no assurance that any or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Series 2017 Bonds.

UNDERWRITING

Merrill Lynch, Pierce, Fenner & Smith Incorporated and the other Underwriters (the “Underwriters”) of the Series 2017 Bonds have jointly and severally agreed, subject to certain conditions, to purchase the Series 2017 Bonds from the Issuer at an underwriters’ discount of \$633,801.31 and to reoffer the Series 2017 Bonds at the initial public offering price set forth on the cover page hereof. The Underwriters have agreed to purchase all of the Series 2017 Bonds if any are purchased. The Series 2017 Bonds may be offered and sold to certain dealers (including dealers depositing Series 2017 Bonds into investment accounts) and to others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Series 2017 Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriters. Bonneville has agreed to pay certain out-of-pocket expenses of the Underwriters, which are included in the discount set forth above.

The Underwriters have provided the following information for inclusion in this Official Statement.

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 (“WFBNA”), one of the Underwriters of the Series 2017 Bonds, 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 2017 Bonds. Pursuant to the WFA Distribution Agreement, WFBNA will share a portion of its underwriting or remarketing agent compensation, as applicable, with respect to the Series 2017 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 2017 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.

Citigroup Global Markets Inc. has informed the Issuer that it has entered into a retail distribution agreement with each of TMC Bonds L.L.C. (“TMC”) and UBS Financial Services Inc. (“UBSFS”). Under these distribution agreements, Citigroup Global Markets Inc. may distribute municipal securities to retail investors through the financial advisor network of UBSFS and the electronic primary offering platform of TMC. As part of this arrangement, Citigroup Global Markets Inc. may compensate TMC (and TMC may compensate its electronic platform member firms) and UBSFS for their selling efforts with respect to the Series 2017 Bonds.

TD Securities (USA) LLC has entered into a negotiated dealer agreement (the “TD Dealer Agreement”) with TD Ameritrade for the retail distribution of certain securities offerings, including the Series 2017 Bonds, at the original issue prices. Pursuant to the TD Dealer Agreement, TD Ameritrade may purchase Series 2017 Bonds from TD Securities (USA) LLC at the original issue prices less a negotiated portion of the selling concession applicable to any Series 2017 Bonds that TD Ameritrade sells.

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

CERTAIN RELATIONSHIPS

Merrill Lynch, Pierce, Fenner & Smith Incorporated, an Underwriter of the Series 2017 Bonds, is an affiliate of Bank of America, N.A., which provided the loan to NIFC VI to construct and acquire the Project and has extended credit in other transactions supported by obligations of Bonneville under related agreements.

WFBNA, an Underwriter of the Series 2017 Bonds, has extended credit in other transactions supported by obligations of Bonneville under related agreements.

Citigroup, an Underwriter of the Series 2017 Bonds, is an affiliate of Citigroup, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements. Citigroup Energy, Inc., an affiliate of Citigroup, Inc., has entered into a power sales contract with Bonneville.

TD Securities (USA) LLC, an Underwriter of the Series 2017 Bonds, is an affiliate of TD Bank, N.A., which has extended credit in other transactions supported by obligations of Bonneville under related agreements.

TAX MATTERS

Interest on the Series 2017 Bonds is includible in gross income for federal income purposes. Ownership of the Series 2017 Bonds may result in other federal income tax consequences to certain taxpayers. Bondholders should consult their tax advisors with respect to the inclusion of interest on the Series 2017 Bonds in gross income for federal income tax purposes and any collateral tax consequences.

Under the laws of the State of Idaho as presently enacted and construed, interest on the Series 2017 Bonds is not subject to the income tax or the franchise tax imposed by the State of Idaho under the Idaho Income Tax Act; *provided, however*, that Bond Counsel expresses no opinion concerning whether the interest on the Series 2017 Bonds held by an S corporation or an electing small business trust is subject to the income tax or the franchise tax imposed by the State of Idaho. Bond counsel will express no opinion with respect to taxation under any other provisions of Idaho law. Ownership of the Series 2017 Bonds may result in other state and local tax consequences to certain taxpayers, and Bond Counsel expresses no opinion regarding any such consequences arising with respect to the Series 2017 Bonds.

The Issuer may deposit moneys or securities with the Trustee in escrow in such amount and manner as to cause the Bonds to be deemed to be no longer outstanding under the Indenture (a “*defeasance*”). A defeasance of the Series 2017 Bonds may be treated as an exchange of the Series 2017 Bonds by the holders thereof and may therefore result in gain or loss to the holders. Bondholders should consult their own tax advisors about the consequences if any of such a defeasance. Bonneville is required to provide notice of defeasance of the Series 2017 Bonds as a material event under its Continuing Disclosure Certificate. Notice of defeasance must also be given to holders pursuant to the terms and provisions of the Indenture.

Each maturity of the Bonds may be sold with original issue discount. Generally, original issue discount is taxed as it accrues. Bondholders should consult their tax advisors concerning the computation of original issue discount accruing in each tax year.

LEGALITY FOR INVESTMENT

The Act provides that the Series 2017 Bonds shall be legal investments in which the following investors may properly and legally invest funds, including capital in their control or belonging to them:

- all public officers and public bodies of the State, its political subdivisions, all municipalities and municipal subdivisions,
- all insurance companies and associations and other persons carrying on an insurance business, all banks, bankers, banking associations, trust companies, savings banks and savings associations, including savings and loan associations, building and loan associations, investment companies and other persons carrying on a banking business,
- all administrators, guardians, executors, trustees and other fiduciaries, and
- all other persons whatsoever who are now or who may hereafter be authorized to invest in bonds or other obligations of the State.

Certain investors may be subject to separate restrictions which limit or prevent their investment in the Series 2017 Bonds.

LEGAL MATTERS

Legal matters incident to the authorization and issuance of the Series 2017 Bonds are subject to the unqualified approving opinion of Chapman and Cutler LLP. Certain legal matters will be passed upon for the Issuer by Williams Bradbury, P.C., Boise, Idaho, and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York.

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to the Idaho Energy Resources Authority (the “Issuer”) by Bonneville for use in the Official Statement, dated September 11, 2017, furnished by the Issuer (the “Official Statement”) with respect to its Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1), Series 2017 (Federally Taxable) (the “Series 2017 Bonds”). The Project is described in the Official Statement under “THE PROJECT.” Such information in this Appendix A is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville’s representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2017 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 1,157 megawatts. (Although the rated capacity of Columbia Generating Station is 1,157 megawatts, Bonneville assumes 1,144 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 2018 of approximately 10,472 annual average megawatts (defined below) under median water conditions and approximately 8,135 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 one-third 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 2017 that, on a planning basis in Operating Year 2018, it will meet 7,671 annual average megawatts of loads, of which approximately 88 percent is forecast to be Preference Customer loads, approximately two percent is forecast to be Reclamation loads for irrigation pumping stations, approximately one percent is forecast to be non-Reclamation federal agency loads, approximately 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 \$917 million in full and on time for Bonneville’s fiscal year ended September 30, 2016 (“Fiscal Year 2016”). Bonneville also prepaid an additional \$959 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 but not limited to lease rental payments for the Project under the Lease-Purchase Agreement and other operating and maintenance expenses, including net billing cash payments and payments under the direct payment agreements and the costs of electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. For a description of the Lease-Purchase Agreement, see the Official Statement under the heading “THE LEASE-PURCHASE AGREEMENT.” In the opinion of Bonneville’s General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including lease rental payments for the Project under the Lease-Purchase Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading “SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2017 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 Background

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 and proposed power rates, see “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates” and “—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019” and “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Power Rates for Fiscal Years 2016-2017.” The rate for most of the power Bonneville has historically sold to DSI is the Industrial Firm Power Rate (“IP Rate”), which is based on the PF Preference Rate and certain adjustments required by federal law.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Fiscal Year 2016 Financial Results

In Fiscal Year 2016, Bonneville made its scheduled United States Treasury payment on time and in full for the 33rd consecutive year. Bonneville recorded net revenues in Fiscal Year 2016 of \$277 million, a decrease of approximately 32 percent from the prior fiscal year. Bonneville had Adjusted Net Revenues of negative \$31 million in Fiscal Year 2016, which is a decrease of \$174 million from Adjusted Net Revenues of \$143 million in Fiscal Year 2015. Adjusted Net Revenues is a financial metric that is not in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and is unaudited; nonetheless, Bonneville management believes the use and reporting of Adjusted Net Revenues assists in reflecting Bonneville’s financial performance from day-to-day operations in applicable fiscal years. The Adjusted Net Revenues metric is net revenues after removing the non-operating effects on Bonneville of certain debt management actions with respect to Net Billed Bonds, including under the Regional Cooperation Debt initiative (hereinafter defined). See “—Regional Cooperation Debt and Related Actions.” For additional details related to Fiscal Year 2016 financial results, see “BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2016.” Two key factors in the decline in net revenues and Adjusted Net Revenues were that revenues from Regional firm power sales and seasonal surplus (secondary) energy sales were lower than Bonneville forecast in establishing its 2016-2017 Final Rates (hereinafter defined). In Fiscal Year 2016, Regional firm power loads declined and short-term energy prices obtained for surplus firm power and seasonal surplus (secondary) energy continued to be affected by low natural gas prices. Energy prices in the western U.S. are primarily influenced by the cost other producers incur to generate energy and the price of fuel, principally natural gas, used to generate the energy.

Bonneville finished Fiscal Year 2016 with Total Financial Reserves of \$724 million, which is a decrease of approximately 39 percent from the prior fiscal year. The Total Financial Reserves is a non-GAAP financial metric and is unaudited; nonetheless, 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. Fiscal Year 2015 Total Financial Reserves were enhanced by cash balances derived other than from operations in the amount of approximately \$220 million, which arose primarily due to the effects of Regional Cooperation Debt refinancing actions. The impact of these planned refinancing activities on Total Financial Reserves in Fiscal Year 2015, when combined with the lower-than-expected Power Services’ revenues in Fiscal Year 2016, led to the decrease in Total Financial Reserves from Fiscal Year 2015 to Fiscal Year 2016. The foregoing revenue developments also led to Bonneville finishing Fiscal Year 2016 with Reserves Available for Risk (“RAR”) of approximately \$602 million, a decline of approximately 29 percent from the prior fiscal year. RAR is a financial metric Bonneville uses as a measure of accumulated cash flow derived from operations. RAR is a non-GAAP financial metric and is unaudited. 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. See “BONNEVILLE FINANCIAL OPERATIONS—Bonneville’s Non-Federal Debt—Electric Power Prepayments,” and “—Management Discussion of Operating Results—Fiscal Year 2016” and “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.” For a discussion of the non-GAAP financial metrics used by

Bonneville (RAR, Total Financial Reserves, and Adjusted Net Revenues), see “BONNEVILLE FINANCIAL OPERATIONS—Bonneville’s Use of Non-GAAP Financial Metrics.”

Fiscal Year 2017 Expectations and Related Information

As of July 28, 2017, Bonneville forecast (i) that Fiscal Year 2017 net revenues would be positive \$328 million, or approximately \$51 million more than net revenues in Fiscal Year 2016, (ii) that Fiscal Year 2017 Adjusted Net Revenues would be negative \$7 million, or approximately \$24 million more than Adjusted Net Revenues in Fiscal Year 2016 and approximately \$26 million higher than Bonneville forecast in establishing rates for Fiscal Year 2017, and (iii) that Bonneville would finish Fiscal Year 2017 with Total Financial Reserves of \$612 million, or approximately \$112 million less than in Fiscal Year 2016, and RAR of \$422 million (Power Services’ RAR of \$11 million and Transmission Services’ RAR of \$411 million), or approximately \$180 million less than in Fiscal Year 2016. The foregoing forecasts reflect changing expectations for certain factors that Bonneville forecast in establishing power rates in its Final 2016-2017 Rates (hereinafter defined): (i) energy market prices continue to be lower than forecast, which affects the revenues Bonneville can obtain from sales of surplus firm power and seasonal surplus (secondary) energy, and (ii) firm Regional loads are lower than forecast arising from changes in commercial usage by end users and reduced DSI sales at the IP Rate. The forecast decline in Total Financial Reserves for the end of Fiscal Year 2017 is also affected by the planned use of \$86 million of financial reserves for debt management purposes (\$71 million related to Power Services and \$15 million related to Transmission Services). See “BONNEVILLE FINANCIAL OPERATIONS—Bonneville’s Use of Non-GAAP Financial Metrics” and Bonneville’s Non-Federal Debt—Bonds for Energy Northwest Net-Billed Projects” and “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Power Rates for Fiscal Years 2016-2017.” Historically, Bonneville has funded \$15 million of transmission capital investment annually with Transmission Services revenues. In Fiscal Year 2017, Bonneville is proposing to either: (i) fund \$15 million of transmission capital investment, or (ii) pay \$15 million of appropriated repayment obligations for amounts appropriated by Congress for transmission facilities of the Federal System.

Analyses as of August 22, 2017, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2017 water supply for the Columbia River basin will be approximately 135 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. While runoff forecasts have improved from those used by Bonneville in its most recent fiscal year end forecasts (as of July 28, 2017), energy prices have been and are expected to be lower than rate case projections.

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

Based on Total Financial Reserve levels, forecasts of revenues and expenses as of the end of the third quarter of Fiscal Year 2017, and other internal updates, Bonneville believes that it will meet its Fiscal Year 2017 United States Treasury payment responsibility on time and in full.

Current Bonneville Power and Transmission Rates

To establish rates of general applicability for electric power and for transmission and related services, in July 2015, Bonneville filed final proposed power and transmission rates for Fiscal Years 2016 and 2017 (the “2016-2017 Rate Period”) with FERC for its review. FERC granted final approval for such rates in February 2016. The rates approved by FERC are referred to herein as the “Final 2016-2017 Rates.”

The Final 2016-2017 Rates reflect an increase in both power and transmission rates over rates in the immediately preceding two-year rate period (the “2014-2015 Rate Period”). Average Tier 1 PF Rates increased by 7.1 percent, to \$33.75 per megawatt hour; average Tier 2 PF Rates increased by 8.1 percent to approximately \$43.09 per megawatt hour; the IP Rate increased by 7.6 percent, to \$41.93 per megawatt hour; and average Transmission Services rates increased by approximately 4.4 percent. See “POWER SERVICES—Certain Statutes and Other Matters Affecting

Bonneville's Power Services—Power Rates for Fiscal Years 2016-2017,” and “TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates.”

Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019

Bonneville began conducting workshops in the spring of 2016 related to developing rates for electric power and transmission and related services for Fiscal Years 2018 and 2019 (the “2018-2019 Rate Period”). Bonneville issued its initial rate proposal for the 2018-2019 Rate Period (the “2018-2019 Initial Rate Proposal”) in November 2016, which began an administrative process that culminated in a final rate proposal for the 2018-2019 Rate Period (the “2018-2019 Final Rate Proposal”) and a record of decision. Bonneville submitted the 2018-2019 Final Rate Proposal and record of decision to FERC on July 26, 2017.

Consistent with longstanding policy, the 2018-2019 Initial Rate Proposal and the 2018-2019 Final Rate Proposal were prepared to assure payment of all costs and 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 clause (“CRAC”) (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 lease rental payments for the Project under the Lease-Purchase Agreement. Payments are made from cash available in the Bonneville Fund. See “BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met.”

Proposed Power Services Rate Increase

The 2018-2019 Final Rate Proposal, issued in July 2017, anticipates that average Tier 1 PF Rates will be \$35.57 per megawatt hour in the rate period, an increase of approximately 5.4 percent over the average Tier 1 PF Rates in effect in the current rate period. Bonneville also expects Tier 2 PF Rates to decrease to approximately \$41.41 per megawatt hour, a 3.9 percent decrease. These rates are exclusive of other proposed surcharges. See “—Proposed Power CRAC and Related Power Rate Level Adjustments.”

The upward pressure on power rates arises primarily from (i) increasing program expenses reflecting the continuation of operations and maintenance expense (“O&M”) and non-routine extraordinary maintenance associated with Federal System infrastructure, (ii) efforts to meet protection and mitigation commitments for fish affected by the operation of the Federal System, (iii) implementation of the new Financial Reserves Policy which will begin to replenish Power Services' financial reserves levels, and (iv) forecast decreases (when compared to forecasts used in establishing current rates) 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.

Proposed Transmission Services Rate Decrease

Based on the 2018-2019 Final Rate Proposal, Bonneville expects transmission and related rates to decrease by approximately 0.7 percent from the average rates now in effect. The decrease in Transmission Services rates is due primarily to cost-management efforts and savings from debt management actions.

Proposed Power CRAC and Related Power Rate Level Adjustments

As part of the 2018-2019 Final Rate Proposal, Bonneville is proposing to continue the use of a rate level adjustment mechanism for power rates (referred to herein as the “Power CRAC”). The Power CRAC proposed in the 2018-2019 Final 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 2016-2017.” As is the case under the Power CRAC established for rates now in effect, an increase in power and related

rate levels under the proposed Power CRAC would occur if certain financial information were to indicate that Power Services' expenses are higher and/or revenues are lower than anticipated.

The proposed 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. The Power CRAC would be triggered if Power Services' RAR were forecast to be below a specified level, referred to as the "Power CRAC Threshold." The Power Services' RAR forecasts would be made shortly before the beginning of the fiscal year in which the Power CRAC would be implemented and would be based on forecasts of Power Services' RAR for the beginning of such fiscal year. Under the 2018-2019 Final Rate Proposal, the Power CRAC Threshold is proposed to be Power Services' RAR of less than zero, as forecast for the beginning of the applicable fiscal year of the rate period. Thus, if Power Services' RAR were forecast to be below zero at the beginning of either fiscal year in the rate period, then Bonneville would (subject to a *de minimis* exception described below) increase power and related rate levels at the beginning of such fiscal year. Thus, if Power Services' RAR were forecast to be below zero at the beginning of Fiscal Year 2019, then Bonneville would (subject to a *de minimis* exception described below) increase power and related rate levels at the beginning of Fiscal Year 2019 to obtain additional revenues in Fiscal Year 2019.

Based on Bonneville's Fiscal Year 2017 financial forecasts as of July 28, 2017 and assuming the 2018-2019 Final Rate Proposal (including the Power CRAC provisions described above) is ultimately approved by FERC on a final basis, the proposed Power CRAC would not trigger for application to Fiscal Year 2018 rate levels. As of July 28, 2017, Bonneville forecast that Power Services' RAR would be approximately \$11 million at the beginning of Fiscal Year 2018.

As proposed in the 2018-2019 Final Rate Proposal, 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 the Power CRAC Threshold and the forecast 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 proposed 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. This \$300 million per fiscal year ceiling on aggregate additional revenues under the proposed Power CRAC would be subject to increase under the terms of the proposed NFB Adjustment described below. The Power CRAC terms in the 2018-2019 Final Rate Proposal 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.

The 2018-2019 Final Rate Proposal also proposes to continue 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 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") are rate adjustment features that would enable Bonneville to recover additional amounts or accelerate cost recovery during the 2018-2019 Rate Period, without a formal and time consuming rate proceeding. These rate adjustment mechanisms 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"). See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

As proposed under the 2018-2019 Final Rate Proposal, the NFB Adjustment would increase the \$300 million Power CRAC ceiling by an amount equal to forecast NFB Financial Effects. Under the NFB Adjustment Bonneville would increase certain power and related rate levels so that the NFB Financial Effects are recovered in the fiscal year following the fiscal year in which an NFB Trigger Event occurs.

As proposed under the 2018-2019 Final Rate Proposal, the Emergency NFB Surcharge would enable Bonneville to increase certain power and related rate levels within the fiscal year in which an NFB Trigger Event occurs to recover NFB Financial Effects expected to occur in such fiscal year. The Emergency NFB Surcharge would take effect only within a fiscal year and only if the TPP for such fiscal year is forecast to be below 80 percent.

After the 2018-2019 Initial Rate Proposal was released the U.S. District Court for the District of Oregon issued a ruling 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” 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. Bonneville does not expect that a new spill plan will be ordered or approved by the court until early calendar year 2018 at the earliest. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—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.” Bonneville included a new “Spill Surcharge” in the 2018-2019 Final Rate Proposal to address potential financial effects arising from the ruling. 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 proposed, the Spill Surcharge would be implemented annually in each of Fiscal Years 2018 and 2019 based on the estimated financial impact of the change in spill operations in the related fiscal year. Bonneville has until May 31 in each fiscal year to determine the amount of the Spill Surcharge. Following a public comment period, Bonneville would increase billings to collect the Spill Surcharge through the remaining months of the related fiscal year. The proposed Spill Surcharge is based on forecasts so it is possible that the Spill Surcharge may recover more or less revenue than the actual financial effects of a new spill plan. However, the financial effects of a new spill plan and the Spill Surcharge will be reflected in Bonneville’s RAR forecast used in making a Power CRAC determination for Fiscal Year 2019. For clarity, the changes in spill arising from the 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 court’s order.

Given the uncertainty about the terms of the anticipated new spill plan, Bonneville is uncertain of its financial impacts and, therefore, the amounts that the Spill Surcharge will be established to recover. However, for reference, in analyzing the effects of the spill operations initially requested by the plaintiffs in their motions for injunction in the Columbia River ESA litigation, Bonneville estimated it could incur approximately \$40 million per year in additional power purchases expense and/or lost revenue. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act.”

Proposed Transmission CRAC

As part of the 2018-2019 Final Rate Proposal, Bonneville is proposing the use for the first time of 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 proposed Transmission CRAC would occur if certain financial information were to indicate that Transmission Services’ expenses are higher and/or revenues are lower than anticipated. The proposed 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, if Transmission Services’ RAR are forecast to be below a proposed Transmission CRAC Threshold (the “Transmission CRAC Threshold”) of \$99 million, as determined shortly before the beginning of the fiscal year at issue. If Transmission Services’ RAR were forecast to be below the \$99 million Transmission CRAC Threshold at the beginning of Fiscal Year 2018 or Fiscal Year 2019, as proposed, Bonneville would increase transmission and related rate levels in an amount of up to \$100 million per fiscal year. The proposed Transmission CRAC Threshold of \$99 million in Transmission Services’ RAR is under consideration in concert with Bonneville’s proposed Financial Reserves Policy as described below and could change in the 2018-2019 Final Rate Proposal. The Transmission CRAC, as proposed in the 2018-2019 Final Rate Proposal did not trigger for implementation to increase Fiscal Year 2018 transmission and related rate levels. Transmission Services’ RAR as of the end of Fiscal Year 2016 were approximately \$444 million.

Financial Reserves Policy

Coincident with the process for developing rates for the 2018-2019 Rate Period, Bonneville adopted a Financial Reserves Policy that seeks to maintain and strengthen Bonneville’s financial health. It will also provide a more balanced approach to the treatment of financial reserves across Power Services and Transmission Services as

Bonneville's experience has shown that Transmission Services' RAR is more stable than Power Services' RAR. The Financial Reserves Policy will be implemented beginning in the 2018-2019 Rate Period and applied in future rate periods. The Financial Reserves Policy will, among other things, lead to increases in the Power CRAC Threshold over time. The Power CRAC Threshold is proposed to remain at zero Power Services' RAR under the 2018-2019 Final Rate Proposal; however, the Power CRAC Threshold for such period could be higher if certain conditions of the Financial Reserves Policy are met. There is no Transmission CRAC under current rates. Bonneville believes that the effect of Financial Reserves Policy over time would be to increase Power Services' RAR and decrease Transmission Services' RAR, while putting in place a framework by which Bonneville's rate levels would be established to maintain an aggregate minimum RAR of approximately \$400 million.

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."

Energy Northwest, a joint operating agency of the State of Washington, and Bonneville have worked together to refinance certain maturities of outstanding Energy Northwest bonds that are supported by Bonneville under certain Net Billing Agreements among Bonneville, Energy Northwest, and over 100 individual Participants (the "Net Billing Agreements." The bonds were issued by Energy Northwest in respect of three nuclear generating projects (the "Energy Northwest Net Billed Projects"), one of which is operating and two of which were terminated in the 1990's prior to the completion of construction. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects." Bonds and other debt instruments issued by Energy Northwest and secured by Net Billing Agreements are referred to herein as "Net Billed Bonds." Since 2001, certain Net Billed Bond refinancings have increased the weighted average maturity of outstanding Net Billed Bonds to match more closely 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 by Energy Northwest to refund outstanding Net Billed Bonds before their maturities (when substantial principal repayments are due) in Fiscal Year 2014 through Fiscal Year 2020. These refinancing Net Billed Bonds 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. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Bonds for Energy Northwest's Net Billed Projects."

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, and (iii) to achieve other debt management goals.

Under the Regional Cooperation Debt approach described above, Bonneville prepaid at the end of each Fiscal Year 2014, Fiscal Year 2015, and Fiscal Year 2016, an additional \$321 million, \$229 million, and \$959 million, respectively, in Federal Appropriations Repayment Obligations over the amounts Bonneville scheduled to repay for the related rate period. 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 2016. The effects of the issuance of Net Billed Bonds issued by Energy Northwest in Fiscal Year 2017 will similarly enable Bonneville to accumulate additional balances in the Bonneville Fund to prepay comparatively high interest Federal Appropriations

Repayment Obligations at the end of Fiscal Year 2017. Energy Northwest and Bonneville have agreed in principle to pursue similar Regional Cooperation Debt actions through Fiscal Year 2020.

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 2018 through Fiscal Year 2020 could exceed \$1.1 billion. If Bonneville and Energy Northwest agree to pursue similar actions beyond Fiscal Year 2020, Bonneville estimates that the aggregate potential principal amount of refinancing Net Billed Bonds to be issued in Fiscal Year 2018 through Fiscal Year 2024 could exceed \$2.2 billion.

When combined with the effects of: (i) the issuance by Energy Northwest of refinancing Net Billed Bonds in Fiscal Year 2014 through Fiscal Year 2017 and (ii) certain other coordinated cash management actions described below, the effect of the planned issuance of refinancing Net Billed Bonds in Fiscal Year 2018 (the “Planned 2018 Regional Cooperation Bonds”) are expected to enable Bonneville to prepay additional comparatively high interest Federal Appropriations Repayment Obligations in the aggregate principal amount of approximately \$2.2 billion by the end of Fiscal Year 2018. Bonneville expects that at the end of Fiscal Year 2018, the aggregate principal amount of refinancing Net Billed Bonds issued by Energy Northwest under the Regional Cooperation Debt initiative for the purpose of prepaying additional Federal Appropriations Repayment Obligations in Fiscal Years 2014-2017 (inclusive of the Planned 2018 Regional Cooperation Bonds) will be approximately \$2.0 billion.

The weighted average interest rate on the Federal Appropriations Repayment Obligations that have been and are planned to be prepaid in Fiscal Years 2014-2017 is approximately 7.15 percent. By contrast, the weighted average yields of refinancing Net Billed Bonds issued in Fiscal Years 2014-2017 is approximately 2.8 percent. It is difficult to forecast the expected weighted average yield of future refinancing Net Billed Bonds including the Planned 2018 Regional Cooperation Bonds; however, Bonneville expects that the average weighted yield on such future refinancing Net Billed Bonds will be less than 6.14 percent.

Short-Term Regional Cooperation Debt and Cash Management Actions

In view of the expected issuance by Energy Northwest of the Planned 2018 Regional Cooperation Bonds, Energy Northwest, with Bonneville’s support, has undertaken additional debt management actions affecting Fiscal Years 2017 and 2018. As more fully described immediately below, Energy Northwest has entered into short-term borrowing arrangements to manage cash flows between Bonneville and Energy Northwest and enable Bonneville to increase the prepayment of certain Federal Appropriations Repayment Obligations at the end of Fiscal Year 2017, over the amount that would otherwise have occurred, by approximately \$500 million. The Fiscal Year 2017 short-term borrowing arrangements will enable Bonneville to save about \$21 million in interest expense in Fiscal Year 2018, 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 Appropriations Repayment Obligations one year earlier than otherwise expected. Bonneville and Energy Northwest undertook similar actions in Fiscal Year 2016 (the related short-term borrowing arrangements by Energy Northwest have been repaid) and the interest expense savings to Bonneville, which are accruing in Fiscal Year 2017, are estimated to be approximately \$17 million.

The Energy Northwest short-term borrowing arrangements now in effect were entered into in October 2016 between Energy Northwest and Bank of America, N.A., for an amount not to exceed \$500 million. Draws by Energy Northwest thereunder have funded and will fund, through the remainder of Fiscal Year 2017, interest on Net Billed Bonds and operation and maintenance expense for the Columbia Generating Station. The amounts borrowed under the short-term borrowing arrangement will be repaid by Energy Northwest with amounts received from Bonneville under existing contract commitments. The amounts borrowed by Energy Northwest under the short-term borrowing arrangement bear interest at variable rates that are under 1.5 percent per annum.

Bonneville believes that Energy Northwest and Bonneville will undertake in future fiscal years short-term debt and cash management actions similar to those described above, albeit in substantially smaller amounts. Bonneville believes that the maximum principal amount of short-term notes issued by Energy Northwest and outstanding at any one time is expected to be \$640 million, which would occur in Fiscal Year 2018.

For more details on Regional Cooperation Debt and related actions, see “BONNEVILLE FINANCIAL OPERATIONS—Bonneville’s Non-Federal Debt—Bonds for Energy Northwest’s Net Billed Projects.

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 “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.

On May 4, 2016, the United States District Court for the District of Oregon (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”) does 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 thereafter ordered it to complete a new biological opinion by December 31, 2018. 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.”

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. See “BONNEVILLE LITIGATION—Columbia River ESA Litigation.”

In filings made before the court in June 2016, the federal government stated that the Corps and Reclamation, in conjunction with Bonneville, “are contemplating approaches for analyzing an array of alternatives for different system operations for all 14 [Federal System] dams and structural modifications that have the potential to improve fish passage, including breaching one or more of the Federal dams that currently provide for adult and juvenile passage. Further, non-operational measures such as habitat actions in the tributaries and estuary, predation management actions, and conservation and safety net hatcheries to offset or minimize environmental impacts may also be evaluated in the event the Action Agencies determine such action would serve as potential mitigation measures.” See “POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The Endangered Species Act.” In the opinion of General Counsel to Bonneville, breaching or other similar major structural changes eliminating one or more of the congressionally authorized purposes of any of the Federal System Hydroelectric Projects 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.

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. In addition, one plaintiff environmental group has requested an injunction to prohibit the Corps from funding ongoing and future capital projects at certain Federal System dams on the lower Snake River. On March 27, 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. The Oregon Federal District Court’s ruling contemplates increased spill in 2018 to allow time to develop system operations that reduce “unintended negative consequences.” Regarding capital investment at Federal System dams on the lower Snake River, the 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.”

The Oregon Federal District Court’s ruling on the motion for injunctions is likely to impact a range of Bonneville activities, but specific information on those effects is not yet available. For reference, in analyzing the effects of the spill operations initially requested by the plaintiffs in their motions for injunction, Bonneville estimated it could incur approximately \$40 million per year in additional power purchases expense and/or lost revenue and face further limitations on the Federal System’s flexibility for integrated power and transmission operations. During the injunction litigation proceedings, however, plaintiffs changed the operations they were requesting. The court has ordered a conferral and planning process over the next year to identify specific operations at each dam; more detailed information on the expected cost of those operations will become available during that process. See “POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—General.” Bonneville’s 2018-2019 Final Rate Proposal includes a “Spill Surcharge” designed to recover the costs of operational changes that may arise from the court’s order. See “Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019—*Proposed Power CRAC and Related Power Rate Level Adjustments*” and “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 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 August 28, 2017, 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 new biological opinion. Bonneville is also unable to predict whether and the extent to which the new 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 ESA or NEPA, 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 \$2.5 billion (excluding “bookouts” from settlements other than by the physical delivery of power) in revenues, or 73 percent, of Bonneville’s total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville’s Transmission Services and Power Services) in Fiscal Year 2016.

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 2018 (August 1, 2017 through July 31, 2018), the total Federal System would be capable of producing approximately 8,135 annual average megawatts of firm energy under Low Water Flows/Critical Water and not accounting for transmission line losses. This generation includes approximately 6,521 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,187 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including hydropower and renewable generation projects), and approximately 427 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 2018.”

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 2018 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 2018.” 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 2018, the Federal System is forecast to generate seasonal surplus (secondary) energy of 1,891 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

3,450 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 2018.” 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 and similar non-federal transactions. In aggregate these arrangements will provide approximately 427 annual average megawatts of energy in Operating Year 2018. See Footnote 13 in the following table “Operating Federal System Projects for Operating Year 2018.”

Operating Federal System Projects for Operating Year 2018

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 2018, 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 2018⁽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⁾
<u>United States Bureau of Reclamation (Reclamation) Hydro Projects</u>						
Grand Coulee including Pump Turbine	1941	33	4,844	2,793	2,403	1,888
Hungry Horse	1952	4	318	111	89	75
Other Reclamation Projects ⁽⁶⁾		<u>19</u>	<u>32</u>	<u>170</u>	<u>151</u>	<u>120</u>
1. Total Reclamation Projects		56	5,194	3,074	2,643	2,083
<u>United States Army Corps of Engineers (Corps) Hydro Projects</u>						
Chief Joseph	1955	27	2,374	1,513	1,344	1,089
John Day	1968	16	2,295	1,387	1,093	779
The Dalles w/o Fishway ⁽⁷⁾	1957	24	1,830	978	815	595
Bonneville	1938	20	960	631	566	387
McNary	1953	14	1,036	632	600	474
Lower Granite	1975	6	737	407	288	149
Lower Monumental	1969	6	810	437	299	150
Little Goose	1970	6	859	420	288	159
Ice Harbor	1961	6	586	287	203	111
Libby	1975	5	483	263	229	189
Dworshak	1974	3	434	292	217	141
Other Corps Projects ⁽⁸⁾		<u>20</u>	<u>204</u>	<u>280</u>	<u>260</u>	<u>215</u>
2. Total Corps Projects		153	12,608	7,527	6,202	4,438
3. Idle Federal Capacity⁽⁹⁾			(7,898)	0	0	0
4. Total Reclamation and Corps Projects (line 1 + line 2 + line 3)		209	9,904	10,601	8,845	6,521
<u>Non-Federally-Owned Projects</u>						
Other Non-Federal Hydro Projects ⁽¹⁰⁾		4	15	43	31	29
Columbia Generating Station ⁽¹¹⁾	1984	1	1,144	1,100	1,100	1,100
Other Non-Federal Projects ⁽¹²⁾		<u>7</u>	<u>0</u>	<u>58</u>	<u>58</u>	<u>58</u>
5. Total Non-Federally-Owned Projects		12	1,159	1,201	1,189	1,187
<u>Federal Contract Purchases</u>						
6. Total Bonneville Contract Purchases⁽¹³⁾		n/a	676	447	438	427
<u>Total Federal System Resources</u>						
7. Total Federal System Resources (line 4 + line 5 + line 6)		221	11,739	12,249	10,472	8,135

Source: 2016 Pacific Northwest Loads and Resources Study, Bonneville, December 2016.

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- (1) Operating Year 2018 is August 1, 2017 through July 31, 2018. Any discrepancies in totals for figures portrayed in this table and the 2016 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 measures prescribed by the NOAA Fisheries biological opinions relating to the Columbia River and tributaries and court-ordered operations; the Fish and Wildlife Service biological opinion for the Snake River and Columbia River dams; operations described in the Council’s Fish and Wildlife Program; and other fish mitigation measures. If and to the extent the effects of new biological opinions or other measures to protect fish and wildlife are different than those assumed in the 2016 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 937 annual average megawatts in most refueling years and 1,100 annual average megawatts in non-refueling years. Columbia Generating Station is not scheduled for refueling in Operating Year 2018 and, therefore, is expected to provide approximately 1,100 annual average megawatts 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 the capability of existing 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 2018, Bonneville forecasts that it will meet approximately 6,733 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. For a 4½ month period that began in February 2016, Alcoa reduced its purchases of power at the IP Rate from 75 average megawatts to ten average megawatts and purchased 300 average megawatts of energy from Bonneville at a negotiated rate that was slightly higher than the spot market for energy. For the past several years the IP Rate has been, and Bonneville expects that it will continue to be, substantially higher than spot market prices for power.

In early May 2016, Bonneville and Alcoa entered into an additional amendment to the Alcoa power sales agreement. The amendment affects the terms of Bonneville's power sales to Alcoa from July 1, 2016 through February 14, 2018. Some of the features of the arrangement include: (i) a continuation of the reduced purchases of electric power by Alcoa at the IP Rate (Alcoa had been purchasing 10 annual average megawatts at the IP Rate since February 2016, but began purchasing 25 annual average megawatts at the IP Rate in March 2017 due to an increase in the price of aluminum above a certain amount as reported on the London Metals Exchange), (ii) the payment by Alcoa of \$1.5 million to Bonneville for the right to make direct market purchases of power other than from Bonneville in most months of the term of the amendment, (iii) a commitment from Alcoa to purchase approximately 250 annual average megawatts of surplus firm power from Bonneville in certain spring months in Fiscal Year 2017, and (iv) to purchase 25 annual average megawatts of firm surplus power during all other months during which the amendment is in effect. These latter purchases will be at a negotiated rate that is slightly higher than the spot market for energy but would also enable Bonneville to interrupt service to Alcoa on short notice thereby providing system operating reserves to Bonneville. Upon expiration of this amendment (starting on February 15, 2018), Alcoa will resume purchasing 75 annual average megawatts at the IP Rate, subject to an early termination charge, through the remaining term of its long-term contract (through September 2022).

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 2018, Bonneville forecasts that it will meet approximately 183 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 2018, Bonneville forecasts that it will meet approximately 113 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 2018, Bonneville forecasts that Other Contract Deliveries will be approximately 593 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. There is ongoing litigation among Bonneville and parties from the Pacific Southwest arising out of the 1999-2001 West Coast power crisis. See "BONNEVILLE LITIGATION—Litigation and Related Disputes Arising from the West Coast Power 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.

Largest Power Services' Customers

The following table lists Power Services' top ten largest customers in terms of their percentage contribution to Power Services' overall sales revenue in Fiscal Year 2016. The table also reflects the applicable customer class of the related customer.

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Bonneville Power Services' Ten Largest Customers By Sales⁽¹⁾
(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2016)

<u>Customer Name (Class)</u>	<u>Approximate % of Sales</u>
Snohomish County PUD No. 1 (Preference)	10%
Cowlitz County PUD No. 1 (Preference)	7%
City of Seattle, City Light Dep't. (Preference)	7%
Pacific Northwest Generating Cooperative (Preference)	6%
Tacoma Power (Preference)	5%
Clark Public Utilities (Preference)	4%
Eugene Water & Electric Board (Preference)	3%
Benton County PUD No. 1 (Preference)	2%
Flathead Electric Cooperative, Inc. (Preference)	2%
Central Lincoln PUD (Preference)	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.

Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products. Bonneville currently provides two primary types of power service under the Long-Term Preference Contracts and its sales agreements with federal agencies: (i) Load Following service, and (ii) 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 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 one Preference Customer purchases a Block-only product from Bonneville in the amount of approximately 3 annual average megawatts.)

Over 100 Preference Customers and all of Bonneville’s nine federal agency customers purchase Load Following service and for Operating Year 2018 Bonneville forecasts that these loads will be approximately 3,106 annual average megawatts. By contrast, 16 separate Preference Customers purchase on a Slice/Block basis. For Operating Year 2018, Bonneville forecasts that its Slice/Block loads will be approximately 3,624 annual average megawatts in total, approximately half of which is expected to be for the Block portion and approximately half of which is expected to be for the Slice portion. For reference, the Slice portion of Slice/Block service currently represents approximately 26.6 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.

Three Preference Customers, with Bonneville’s consent, have elected under certain provisions of their Long-Term Preference Contracts to change the type of power product they will purchase from Bonneville. By Fiscal Year 2020: (i) the aggregate amount of Slice that Bonneville will sell will decline to 22.3 percent of the system (currently the amount is 26.6 percent), (ii) Block sales will increase by approximately 236 annual average megawatts, and (iii) Load Following sales will increase by 36 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.

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 6,945 annual average megawatts for Fiscal Year 2018.

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. Bonneville has agreed to provide power service to a new Preference Customer beginning in Fiscal Year 2018. The new customer is an electric power cooperative with power loads expected to be less than five annual average megawatts through Fiscal Year 2028. 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 72 annual average megawatts of Tier 2 Loads in Fiscal Year 2017. In Fiscal Year 2015 and Fiscal Year 2016, Tier 2 Loads were 75 annual average megawatts and 72 annual average megawatts, respectively. As required under the Long-Term Preference Contracts, those customers requesting that Bonneville meet their Tier 2 Loads through Fiscal Year 2019 have made their elections. Bonneville is obligated to meet approximately 122 annual average megawatts of Tier 2 Loads in Fiscal Year 2018 and 143 annual average

megawatts in Fiscal Year 2019. Similar Tier 2 Load elections and advance notice to Bonneville are required in the five fiscal years beginning with Fiscal Year 2020, and the four fiscal years beginning with Fiscal Year 2025.

Comparison of Tier 1 PF Rates and Tier 2 PF Rates. Through the 2018-2019 Rate Period, Bonneville expects that Tier 1 PF Rates will 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) will 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, it is possible that Tier 2 PF Rates could be lower than Tier 1 PF Rates starting in Fiscal Year 2020. During the 2014-2015 Rate Period, average Tier 2 PF Rates were \$39.86 per megawatt hour and average Tier 1 PF Rates were \$31.50 per megawatt hour. Under the 2016-2017 Rates, average Tier 2 PF Rates are approximately \$43.09 per megawatt hour and average Tier 1 PF Rates are approximately \$33.75 per megawatt hour. Under the 2018-2019 Final Rate Proposal, Bonneville expects that average Tier 2 PF Rates will be approximately \$41.41 per megawatt hour and that average Tier 1 PF Rates will be approximately \$35.57 per megawatt hour.

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 2016 Loads and Resources Study, Bonneville projected that it would have energy surpluses of approximately 220 annual average megawatts in Operating Year 2018, 28 annual average megawatts in Operating Year 2019, and 168 annual average megawatts in Operating Year 2020, assuming Low Water Flows/Critical Water and transmission line losses. If these planning surpluses materialize, Bonneville anticipates that it will sell the related power in west coast energy markets. Between Operating Years 2021 and 2027, Bonneville forecasts annual planning deficits that vary between 75 annual average megawatts (in Operating Year 2021) and 267 annual average megawatts (in Operating Year 2027). 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.”

In early calendar year 2016, the Council released its Seventh Northwest Conservation and Electric Power Plan (the “Seventh Power Plan”), which 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 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 resource portfolio standards.

Bonneville’s current 2016-2021 Energy Efficiency Action Plan forecasts that Bonneville will achieve 580 average megawatts of conservation in partnership with its Preference Customers and others through 2021, but a final amount has not been determined. 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 2013 (the “2013 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. Bonneville is working with its customers on a framework for the new Resource Program and has been holding public workshops on the proposed changes and associated time lines. Bonneville is currently anticipating that it will complete its next Resource Program in the summer of 2018.

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, 2019.

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 \$214 million in aggregate for Fiscal Year 2017 (aggregate program benefits of approximately \$292 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 2016, the aggregate overpayment of Residential Exchange Program benefits that have not yet been recouped by Bonneville (and conveyed to Preference Customers) was approximately \$230 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. “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 2014 through 2016.

**Fish and Wildlife Financial Impacts by Type
(Fiscal Years 2014-2016, dollars in millions)**

	2016	2015	2014
Direct Costs	\$ 495	\$ 494	\$ 464
Estimated Operational Impacts⁽¹⁾:			
Replacement Power purchases	50	67	196
Foregone Power Revenues	77	196	123
Total Fish and Wildlife	\$ 622	\$ 757	\$ 783

⁽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 for 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 providing funding under the Columbia Basin Fish Accords entered into with certain tribes and the states of Idaho, Montana, and Washington. 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.

The 2014 Columbia River System Supplemental Biological Opinion reviewed the status of the related species and new science on topics related to the biological opinion, scrutinized the detail provided by the Action Agencies on specific mitigation measures and analyzed the scientific support for those measures, and evaluated whether more aggressive actions were necessary to meet the standards under the ESA.

The 2014 Columbia River System Supplemental Biological Opinion also includes continued implementation of a wide range of measures (over 70 mitigation actions), initially included in the 2008 Columbia River System Biological Opinion. These measures include improvements in downstream juvenile passage survival to achieve performance standards, including structural modifications to Federal System dams as well as spill and other operations that are timed to the needs of individual listed fish species, an expanded habitat program, an expanded predation-management program, a timetable for site-specific fish hatchery consultations and reforms, and extensive research, monitoring, and evaluation to support adaptive management.

The 2014 Columbia River System Supplemental Biological Opinion also identified contingent actions that would be implemented, as appropriate, in the event of the occurrence of certain triggering events evidencing biological decline of the ESA-listed species. These contingent actions include actions that could be implemented if needed in less than a year. These short-term contingent actions include hydro-operations actions such as spill beyond that required to meet hydro-system dam fish passage survival performance standards, fish transportation modifications, fish hatchery operations, fish predator management and fish harvest restrictions.

The potential longer-term contingent actions that would take more than one year to implement include such actions as alterations to fish predation management approaches, harvest practices, hatchery practices, and study plans for hydro-system modifications, and, as carried forward from preceding biological opinions, an approach to long-term contingency actions in the event there is a significant decline in the status of either of two listed Snake River species. For a decline in the two Snake River species, one contingent action in the 2014 Columbia River System Supplemental Biological Opinion is the preparation of a study of breaching one or more of the four lower Snake River hydroelectric dams of the Federal System. Breaching these dams would interfere substantially with hydroelectric generation of the Federal System. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act.”

In the opinion of General Counsel to Bonneville, breaching or other similar major structural changes eliminating one or more of the congressionally authorized purposes of any of the federally-owned 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 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.” The court has ordered the federal government to complete the new environmental impact statement by 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.

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 Final 2016-2017 Rates, 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 2016-2017 Rates, 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 has included in its 2018-2019 Final Rate Proposal any additional costs or risks from ESA compliance that it identified in time to include in the Proposal. 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. Bonneville has proposed to continue similar provisions under the 2018-2019 Final Rate Proposal and has also proposed a new Spill Surcharge to ensure recovery of costs from potential increases in planned spill levels. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019" 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 2016-2017."

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 \$48 million in aggregate in Fiscal Year 2017 through Fiscal Year 2021 (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 2016, Bonneville was responsible for \$1.4 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 \$342 million through Fiscal Year 2021. This would bring the total amount of Bonneville's Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation to approximately \$1.8 billion by the end of Fiscal Year 2021. The amounts ultimately appropriated under the Columbia River Fish Mitigation program (through Fiscal Year 2021 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 2021, 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 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.

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 2016, the remaining unobligated commitment under all Columbia Basin Fish Accords, after taking into account later Accords and modifications, is approximately \$345 million. (These Accords do not include arrangements relating to Willamette basin 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 purposes such as 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 Accords, the participating tribes and states agree that the federal government’s requirements under the ESA, the Federal Water Pollution Control Act, and the Northwest Power Act are satisfied as to the identified Federal System Hydroelectric Projects in the Snake River and Columbia River drainages. Under its Accord, the State of Washington agreed, among other things, to support the federal government’s position in the ESA litigation.

The Columbia Basin Fish Accords begin to expire in 2018. The Action Agencies have been discussing whether to pursue successor agreements with interested states and tribes. Bonneville is unable to predict whether the Accords will be continued.

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, the Corps obtained approval from Congress to undertake structural modifications to certain Willamette Project dams to provide downstream passage for juvenile salmon and

to improve downstream water temperatures. The precise modifications that will be proposed and implemented, and the timing of their construction, will depend on congressional appropriation enactments and future public processes; however, the general plan outlined by the Corps involves the installation of fish collection facilities to assist downstream migrating juvenile fish and a temperature control facility which assists in preventing over-cold water conditions during upstream fish migration and over-warm water conditions during fish incubation. Starting in calendar year 2009, these modifications were and are expected to be funded by specific federal appropriations, primarily to the Corps under the Columbia River Fish Mitigation program. According to the current general plan, the modifications would be designed, installed, tested and placed in service over a multi-year period, with the first of the major structural components expected to be placed in service during Fiscal Year 2022, and the last of the major structural components expected to be placed in service during Fiscal Year 2027.

Using Bonneville's existing appropriations repayment criteria, after the modifications are funded through federal appropriations and placed in service, it is expected that they will be added to Bonneville's Federal Appropriations Repayment Obligations and Bonneville will be required to establish rates to repay approximately 42 percent of the associated costs of the modifications, which is the proportion of the overall Willamette Project's costs that are assigned to be recovered in Bonneville's power rates. Under the applicable repayment criteria, the 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.

The structural modifications at the Willamette Project dams are not expected to materially decrease the amount of Federal System power. However, Bonneville expects power-production costs for the Willamette Project will gradually increase, particularly beginning in Fiscal Year 2022 as the first of the major structural modifications are expected to be placed in service and the costs of other measures, such as streamflow enhancements and fish habitat/hatchery improvements, are realized. 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 these possible future modifications to the Willamette Project would have a significant effect on Bonneville's overall power rate levels.

Bonneville and the State of Oregon have signed an agreement that, upon successful completion, permanently fulfills Bonneville's longstanding wildlife mitigation obligations 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 continue to fund 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 \$104 million, \$78 million, and \$73 million in Fiscal Years 2014, 2015, and 2016, 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.

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 2016, Integrated Program expense was \$258 million, and Federal System capital investment was \$16 million. As of July 31, 2017, Bonneville forecasts that Fiscal Year 2017 expenses and capital program investments will be \$258 million and \$21 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 2016-2017

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's 2016-2017 Final Rate Proposal for power and transmission rates of general applicability and FERC has granted final approval thereof. The final rates for the 2016-2017 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 7.1 percent over the prior average rates, to \$33.75 per megawatt hour. Under the Final 2016-2017 Rates, average Tier 2 PF Rates are 8.1 percent higher than in the prior rate period, increasing to \$43.09 per megawatt hour. Tier 2 PF Rates apply to certain incremental loads that Preference Customers require Bonneville to meet. Bonneville currently sells less than 100 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 2016-2017 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 2016-2017 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 2016-2017 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 and time consuming rate proceeding.

The Final 2016-2017 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 2016-2017 Rate Period, without a formal and time consuming 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 2016-2017 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 2016-2017 Rate Period did not occur.

The Emergency NFB Surcharge in the Final 2016-2017 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 were 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 2017.

In addition to the foregoing cost recovery adjustments, under the Final 2016-2017 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 Discussion of Operating Results—Fiscal Year 2015," "—Bonneville's Use of Non-GAAP Financial Metrics," and "—Banking Relationship between the United States Treasury and Bonneville."

Bonneville's 2018-2019 Final Rate Proposal includes carrying forward the approach of establishing base power rates and including intra-rate period cost recovery tools such as the Power CRAC, the NFB Adjustment and the Emergency NFB Surcharge, under terms substantially similar to those in the 2016-2017 Final Rates. In addition, Bonneville has proposed a new Spill Surcharge to ensure recovery of costs from potential increases in planned spill levels. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019."

Historical PF Preference Rate Levels

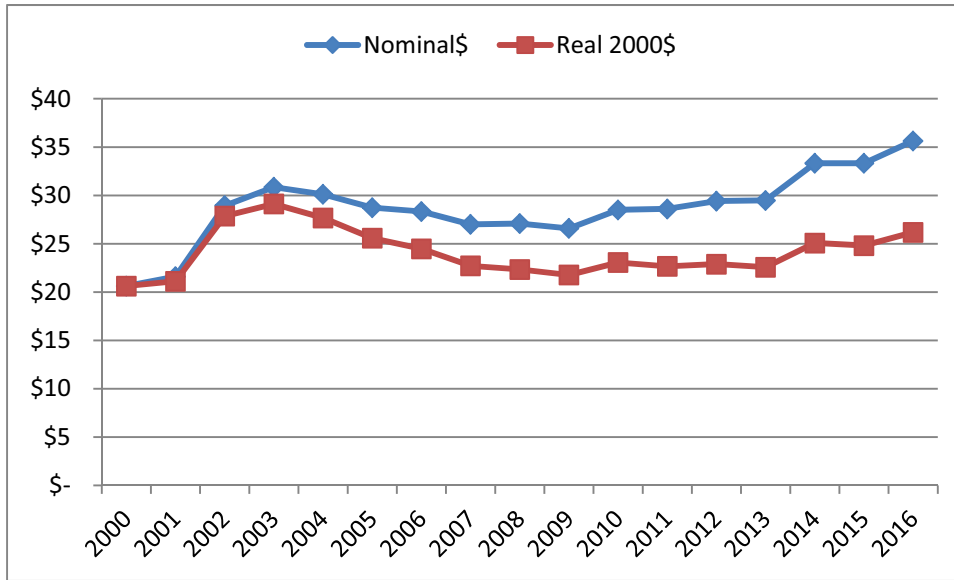
As shown in the following table, Bonneville's average PF Preference Rates have remained between \$20 per megawatt hour and \$36 per megawatt hour in nominal (actual) dollars, and between \$20 per megawatt hour and \$30 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2016. 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 Power Crisis in 1999-2001. See "BONNEVILLE LITIGATION—Litigation and Related Disputes Arising from the West Coast Power Crisis in 1999-2001." Since then, such rates have been stable, especially when viewed from an inflation-adjusted perspective, as shown in the following chart.

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Historical Average PF Preference Rates

Nominal (Actual) and Real (Inflation-Adjusted) Average PF Preference Rate Levels, Per Megawatt Hour, Fiscal Years 2000—2016



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 \$947 million in revenues from the sale of transmission and related services, or approximately 27 percent of Bonneville's total revenues from external customers (and excluding revenues otherwise arising from inter-functional transactions between Bonneville's Transmission Services and Power Services) in Fiscal Year 2016.

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 2016-2017), a large Preference Customer that purchases very little transmission for its own generating resources pays Bonneville approximately \$4.28 per megawatt hour for transmission service and approximately \$33.75 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, such as the Project, needed to maintain reliability and new transmission projects that will provide additional, long-term firm transmission service for entities seeking new transmission service in the Region. In recent years, many of the requests for new transmission service have been submitted by customers developing new power generation projects, primarily wind generation, both inside and outside the Region. As reflected in the 2018-2019 Initial Rate Proposal, Bonneville expects to make transmission system investments in Fiscal Years 2017 through 2026 averaging approximately \$560 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 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 \$39 million in Fiscal Year 2016. Bonneville estimates that the transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments will be \$22 million in Fiscal Year 2017, approximately \$17 million in Fiscal Year 2018, and approximately \$15 million in Fiscal Year 2019. While Bonneville expects the transmission service credit offsets to begin to decrease in Fiscal Year 2017, it is possible that the amount of such credits could increase in future years depending on the development of new generation projects (particularly wind projects) that interconnect to the Federal Transmission System.

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.”

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. FERC also may 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 adopted terms and conditions for a non-discriminatory open access transmission tariff and has voluntarily filed its tariff with FERC to obtain reciprocity status. Bonneville filed an Order 890 tariff on October 3, 2008. FERC approved most of Bonneville’s tariff in an order issued July 15, 2009, but denied reciprocity pending resolution of certain limited issues. Bonneville’s subsequent request for rehearing was denied. After seeking public review and comment, Bonneville voluntarily filed a new Order 890 tariff with FERC in 2012 seeking reciprocity approval. Several parties filed protests to certain aspects of Bonneville’s new Order 890 tariff and FERC issued an order denying Bonneville reciprocity. Bonneville did not file for rehearing. Bonneville’s Order 890 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 not subject to Orders 889 and 717, non-jurisdictional utilities must adhere to them in order to obtain reciprocity. 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. The lease rental payments for the Project under the Lease-Purchase Agreement will be recovered by Bonneville in Transmission Services’ rates.

Rates for Transmission and Ancillary and Control Area Services

Bonneville’s Fiscal Years 2016-2017 transmission rates, which FERC approved on February 2, 2016, reflect an average increase of approximately 4.4 percent over Fiscal Years 2014-2015 rate levels. Construction of new lines and replacements to maintain reliability and facilitate the integration of renewable resources, such as wind, accounted for a large portion of the transmission rate increase. Increased compliance requirements and additional cyber and physical security requirements and other operational and maintenance expenses also contributed to the transmission rate increase.

Bonneville’s Fiscal Years 2016-2017 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.

Bonneville has proposed a decrease in rates for transmission and ancillary and control area services under the 2018-2019 Final Rate Proposal. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019.”

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 2016. 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 2016)

<u>Customer Name (Class)</u>	<u>Approximate % of Sales</u>
Puget Sound Energy Inc. (IOU)	12%
PacifiCorp (IOU)	11%
Portland General Electric Company (IOU)	9%
Powerex Corp. (Power Marketer)	7%
City of Seattle, City Light Dep’t. (Preference)	5%
Avangrid Renewables LLC (<i>formerly known as Iberdrola Renewables Inc.</i>) (Wind Developer)	5%
Snohomish County PUD No. 1 (Preference)	4%
Pacific Northwest Generating Cooperative (Preference)	2%
Hermiston Power LLC (Power Marketer)	2%
Clark Public Utilities (Preference)	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. Bonneville continues to evaluate 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.

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 United States Court of Appeals for the Ninth Circuit ("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 four Superfund sites where Bonneville has been or may be identified as a Potentially Responsible Party for some of the contamination. There are also two 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 six 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 "—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. On October 7, 2016, the Department of State approved this negotiation authorization and is now working with Canadian officials to begin negotiations.

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. Most recently, the President's Budget Submission to Congress on May 23, 2017 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 this proposal or any other proposal will be 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 lease rental payments for the Project under the Lease-Purchase Agreement. In March 2017, the United States Treasury reached the debt ceiling but the United States Treasury has indicated that by utilizing various measures, the funding of the federal government's operations can continue without disruption absent an increase in the debt ceiling until sometime in the third quarter of calendar year 2017. Bonneville is unable to predict whether or when the Congress will enact an increase in the United States Treasury debt ceiling or the impacts that the failure to enact such an increase could have on Bonneville's financial operations.

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 would 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 is being challenged in court (oral argument was held in October 2016 and the parties await a decision from the court), and the Supreme Court has placed a stay on the Clean Power Plan which prevents implementation until the legal challenge is complete. On March 28, 2017, President Trump issued an Executive Order entitled "Promoting Energy Independence and Economic Growth," which requires that the EPA review the Clean Power Plan and related rules and agency actions in light of new energy policy objectives. The new energy policy objectives include taking appropriate actions to promote clean air and clean water for the American people, while also respecting the proper roles of Congress and the states concerning these matters. Once the EPA Administrator takes actions pursuant to the executive order, he is directed to notify the U.S. Attorney General of such actions so that the U.S. Attorney General can seek a stay of the litigation or seek other appropriate relief (consistent with the executive order) while the EPA completes its administrative process.

In addition to the Clean Power Plan, 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 greenhouse gas 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-based generation in the Federal System, to the extent that global warming 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 4,782 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 through 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.

Bonneville estimated in 2011 that on an expected value basis it will compensate wind generators an average of approximately \$10 million per fiscal year for displacement and that under extreme conditions of very high streamflow, high wind generation and low power loads, compensation could exceed \$50 million in a given fiscal year. Bonneville expects that the amount of wind generation within its balancing authority will decline substantially in the next several years as certain wind resources transfer to other balancing authorities; however, Bonneville believes that its balancing area responsibilities will include at least 1,528 megawatts of wind generation for the foreseeable future. Bonneville has not updated the foregoing oversupply compensation studies, but believes that the expected reduction in its balancing area authority responsibilities for wind generators could modestly affect the expected value of displacement compensation it would pay under the oversupply protocol but limit the high range of possible compensation.

As a result of its oversupply management actions in Fiscal Year 2012, Bonneville displaced 49,654 megawatt hours of generation resulting in eligible displacement costs of approximately \$3 million. Bonneville's oversupply management has not resulted in compensable amounts to wind generators or others in Fiscal Year 2013 through Fiscal Year 2016. Oversupply conditions have occurred in March 2017 through June 2017. As of July 31, 2017, Bonneville estimates that it displaced 139,368 megawatt hours of generation resulting in eligible displacement costs of approximately \$2 million during Fiscal Year 2017. Oversupply conditions can arise rapidly and are subject to change. Bonneville does not expect that additional oversupply management actions resulting in compensated displacement will occur during the remainder of Fiscal Year 2017.

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.

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, 2016, Bonneville had repaid \$13.4 billion of principal of the Federal System investment and had approximately \$2.9 billion principal amount outstanding with regard to such appropriated investments and \$4.8 billion principal amount outstanding in bonds issued by Bonneville to the United States Treasury. Congress has continued to, and is expected to continue to, appropriate amounts for certain fish and wildlife investments in the Federal System. See the discussion of the Columbia River Fish Mitigation in "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Bonneville's repayment obligations include the payment of "irrigation assistance," which relates to appropriations provided to Reclamation to construct irrigation facilities associated with its Federal System projects. Bonneville's irrigation assistance obligation is limited to an amount of appropriations that is deemed under Reclamation policy to be beyond the ability of irrigators to pay. Examples of appropriated irrigation investments include water pumps, reservoir facilities and canals within the authorizations for the Federal System Hydroelectric Projects owned by Reclamation. These repayment obligations do not incur interest. In keeping with the principle (as embodied in DOE Order RA 6120.2) of scheduling repayments on the basis of highest interest repayment obligations first, payments for irrigation assistance are typically scheduled for recovery in Bonneville power rates in the year in which the expected life of the related facility (as determined near the time of construction) is reached. Bonneville expects that these payments will range between \$6 million and \$57 million per year over the next ten years.

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 \$4.8 billion were outstanding as of the end of Fiscal Year 2016. 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 2016, the interest rates on the outstanding bonds ranged from 0.5 percent to 5.9 percent with a weighted average interest rate of approximately 3.0 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2016, Bonneville's outstanding bonds issued to the United States Treasury included \$800 million in variable rate bonds at an average interest rate of 0.5 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. In Fiscal Year 2017, Bonneville does not expect to draw on the short-term expense borrowing arrangement.

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, 2016, aggregate Non-Federal Debt outstanding was approximately \$8.0 billion. By way of comparison, as of September 30, 2016, the principal amount of unrepaid

appropriations for Federal System investments was approximately \$2.9 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was \$4.8 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.”

Bonds for Energy Northwest’s Net Billed Projects

Bonds issued by Energy Northwest bonds issued for its Net Billed Projects represent the largest single component of Non-Federal Debt: \$5.6 billion out of a total of \$8.0 billion aggregate Non-Federal Debt, as of September 30, 2016. Bonneville works with Energy Northwest on debt management actions relating to the Net Billed Bonds See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.”

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

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

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

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

The Net Billing Agreements require each Participant to pay Energy Northwest the amount set forth in its Billing Statement 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 amounts potentially subject to net billing are substantial. The debt service on the Net Billed Bonds in Fiscal Year 2016 was \$240 million. In addition, Energy Northwest also incurs substantial operating expense for the Columbia Generating Station. See “BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results,” and “POWER SERVICES—Description of the Generation Resources of the Federal System—Other Power Resources and Contract Purchases.”

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. These actions enabled Bonneville to accumulate additional cash balances in the Bonneville Fund to cover approximately \$71 million of energy efficiency program expense in Fiscal Year 2016 and are expected to enable Bonneville to cover approximately \$67 million in energy efficiency program expense in Fiscal Year 2017.

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 2016, 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 2017. The reserves are unexpended amounts that were derived from the power prepayment program. Bonneville estimates that the foregoing planned use of power prepayment balances will reduce interest expense in Fiscal Year 2017 by approximately \$4 million. Bonneville is similarly deferring the use of power prepayment balances in Fiscal Year 2017 which will result in expected interest savings of approximately \$3 million in Fiscal Year 2018. This use of power prepayment balances could be repeated in future fiscal years depending on several factors, including the issuance by Energy Northwest of future refinancing Net Billed Bonds under the Regional Cooperation Debt initiative. Thus, it is possible that Bonneville may continue to defer, on an annual basis for several years, the expenditure of the remaining balance of power prepayments on Federal System hydropower capital investments.

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 Northwest Infrastructure Financing Corporation VI (“NIFC VI”), the Port of Morrow, Oregon (the “Port of Morrow”), and the Issuer and long-term lease-purchase arrangements with Northwest Infrastructure Financing Corporation and the Port of Morrow. The Series 2017 Bonds when issued will be included in Non-Federal Debt under the Lease-Purchase Program.

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 \$2.1 billion as of September 30, 2016. Of the foregoing amount, the aggregate outstanding principal amount of publicly-issued lease-purchase bonds was approximately \$931 million.

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.” In connection with the issuance of the Series 2017 Bonds, the Issuer will use most of the proceeds thereof to acquire the Project from NIFC VI.

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 defer expending the remaining \$82 million in prepayments on Federal System hydroelectric facility investments until at least Fiscal Year 2018. The deferral, in concert with certain actions under the Regional Cooperation Debt initiative, will enable Bonneville to prepay a like amount of Federal Appropriations Repayment Obligations earlier than would otherwise occur.

As of September 30, 2016, outstanding Non-Federal Debt associated with electric power prepayments was \$285 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, 2016, outstanding Non-Federal Debt for generating resource acquisitions was \$93 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 2014 through 2016.

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Non-Federal and Federal Debt, Fiscal Years 2014-2016
(Dollars in millions)

Non-Federal and Federal Debt Outstanding

Projects Financed with Non-Federal Debt	2016	2015	2014
Non-Federal Generation			
Columbia Generating Station	\$3,636	\$3,453	\$3,305
Cowlitz Falls Project	79	82	85
Terminated Generation			
Nuclear Project No. 1	865	903	913
Nuclear Project No. 3	1,068	1,133	1,144
Northern Wasco Hydro Project	14	16	17
Lease-Purchase Program/Capital Leases	2,069	1,650	1,455
Customer prepaid power purchases	285	302	319
Other	--	--	2
Total Non-Federal Debt	\$8,016	\$7,539	\$7,240
Federal Debt			
Borrowings from U.S. Treasury	4,759	4,649	4,242
Federal appropriations	2,430	3,514	3,650
Federal appropriations (not yet scheduled for repayment)	436	388	440
Total Federal Debt	\$7,625	\$8,551	\$8,332
Total Debt	\$15,641	\$16,090	\$15,572

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

Bonneville's Capital Program

Bonneville operates in a capital intensive industry and expenditure levels for its capital program have been substantial. As with all capital investments, there is potential that certain investments may not be constructed to completion, provide the results expected, or achieve functionality for their full expected useful lives. The following table depicts Bonneville's capital investment levels by asset category for Fiscal Years 2012-2016. 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)

	2012	2013	2014	2015	2016	Total
Transmission ⁽²⁾	\$557	\$506	\$613	\$734	\$552	\$2,962
Federal System Hydro	214	206	173	167	187	947
Energy Efficiency	80	78	78	87	0	323
Fish and Wildlife	58	52	37	21	16	184
Facilities, Information Technology, Security ⁽²⁾	44	41	28	28	22	163
Total	\$953	\$883	\$929	\$1,037	\$777	\$4,579

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

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

To date Bonneville has met its capital program needs through various sources that include borrowing from the United States Treasury, and transactions involving Non-Federal Debt, as described above. Bonneville also uses funds from reserves and funds from customers in connection with “Projects Funded in Advance.” Projects Funded in Advance are specific transmission capital investments that are made by Bonneville in the Federal Transmission System at the request of a customer or to meet a customer’s transmission needs. The customer provides funds to Bonneville to construct all or a portion of the related facilities and in some circumstances certain customers may receive offsetting payment credits in future transmission bills from Bonneville. Bonneville owns the facilities in its own name. See “TRANSMISSION SERVICES—Bonneville’s Federal Transmission System.” The following table presents Bonneville’s capital funding sources for Fiscal Year 2012 through Fiscal Year 2016. 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)

	2012	2013	2014	2015	2016	Total
Borrowing from United States Treasury	\$664	\$632	\$544	\$647	\$504	\$2,991
Lease-Purchases ⁽²⁾	235	207	248	249	255	1,194
Projects Funded in Advance	39	9	7	2	3	60
Reserve Funding	15	15	15	15	15	75
Electric Power Prepayments ⁽³⁾	-	20	115	124	0	259
Total	\$953	\$883	\$929	\$1,037	\$777	\$4,579

(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.

During the spring of 2012, Bonneville outlined a general approach and subsequently introduced a systematic, value-based method of prioritizing Bonneville capital investments that considers the relationship between capital investment and O&M expense to ensure capital is deployed optimally across competing 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 June 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 are expected to be amortized and recovered in future rate periods starting no earlier than Fiscal Year 2020.

In connection with developing the 2018-2019 Final 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)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission	\$467	\$461	\$458	\$604	\$624	\$636	\$597	\$580	\$578	\$596	\$5,601
Fed System Hydro	206	236	258	281	306	331	338	344	351	358	3,009
Fish and Wildlife	45	51	44	38	34	29	29	36	37	37	380
Facilities, Information Technology, Security	55	49	68	41	45	45	47	29	40	33	452
AFUDC ⁽¹⁾	50	32	30	30	31	31	30	30	30	30	324
Total	\$823	\$829	\$858	\$994	\$1,040	\$1,072	\$1,041	\$1,019	\$1,036	\$1,054	\$9,766

⁽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 \$826 million in additional capital requirements from July 2017 through June 2026. 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 adherence to the capital strategy will assure that Bonneville will meet capital and financial liquidity needs, through at least Fiscal Year 2026. The capital strategy is predicated in part on an assumption that Bonneville will reserve \$750 million of its United States Treasury borrowing capacity to be available for short-term borrowing for liquidity. The use of Non-Federal Debt is essential to Bonneville’s capital strategy: absent the use of Non-Federal Debt and other funding arrangements, Bonneville estimates that it could reach the ceiling amount of its authority to borrow from the United States Treasury as early as Fiscal Year 2019.

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.

Future Lease-Purchases. Bonneville expects that prior to spring of 2018 the IERA will establish one Bonneville-supported \$200 million short-term bank facility to fund construction of \$200 million of additional transmission facilities. The IERA has taken no official action to authorize such short-term bank facility.

For future fiscal years, Bonneville assumes that the amount of short- and long-term lease-purchase arrangements and the bank loans and bonds secured thereby could be up to 50 percent of the Federal Transmission System’s capital needs. Based on this assumption, Bonneville expects that capital expenditures from funds provided under lease-purchase agreements will average up to \$280 million annually over Fiscal Years 2017-2026. Bonneville expects that up to \$280 million per year in short-term bank facilities will be established to fund construction, pending repayment with the proceeds of long-term lease-purchase bonds. Bonneville believes that the aggregate principal amount of short-term, lease-purchase construction bank facilities could exceed \$1 billion at any one time. See “—Bonneville’s Non-Federal Debt.” 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 \$826 million from July 2017 through June 2026. Additional Net Billed Bonds for additional capital investments for the project may be issued thereafter. In addition, Bonneville expects that it and Energy Northwest will continue to restructure Net Billed Bond debt to extend the average maturity of the outstanding principal balance of such debt to match more closely the originally expected economic useful lives of the facilities financed thereby. 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 \$234 million, \$137 million, and \$31 million, respectively, in Fiscal Year 2016.

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 lease rental payments for the Project under the Lease-Purchase Agreement. 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 \$189 million to \$564 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 2019. 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 2016 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 \$1.9 billion in Fiscal Year 2016, approximately \$959 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 2017. 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 lease rental payments for the Project under the Lease-Purchase Agreement securing the Series 2017 Bonds and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including lease rental payments for the Project under the Lease-Purchase Agreement securing the Series 2017 Bonds 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 "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2017 BONDS," and see "—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—Bonds for Energy Northwest's Net Billed Projects" and "—Direct Pay Agreements" above. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Energy Northwest Net Billing Agreements for the Net

Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. Bonneville and Energy Northwest have entered into Direct Pay Agreements under which Bonneville pays the costs of the Net Billed Projects on a current cash basis thereby reducing the use of net billing to meet the costs of the Net Billed Projects. See “—Direct Pay Agreements.”

Bonneville also has obligations to reduce future amounts receivable from certain power customers that have prepaid for electric power, see “—Bonneville’s Non-Federal Debt—Electric Power Prepayments,” and from certain transmission customers that have provided lump sum payments to Bonneville for it to construct or install certain transmission facilities necessary to provide transmission service to the customers. The electric power prepayments involve the recognition (as credits) of the prepayments in future electric power bills by Bonneville. The credits for prepaid power will be approximately \$31 million per fiscal year through Fiscal Year 2028. Bonneville estimates that transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were \$39 million in Fiscal Year 2016 and will be \$22 million in Fiscal Year 2017.

The foregoing credits have the effect of reducing Bonneville’s future cash revenue from the participating customers, and will reduce in the future the amount of cash in the Bonneville Fund that would otherwise be available to meet Bonneville’s cash payment obligations, including lease rental payments for the Project under the Lease-Purchase Agreement.

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

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

While all amounts in the Bonneville Fund are available to pay Bonneville’s costs without regard to whether such costs are Power Services’ costs or Transmission Services’ costs, some reserves are derived from Power Services’ rates and operations and some are derived from Transmission Services’ rates and operations. (As of the end of Fiscal Year 2016, approximately \$208 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 \$516 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.

Adjusted Net Revenues. In Fiscal Year 2013, Bonneville commenced utilizing and reporting a new financial metric, "Adjusted Net Revenues." While the Adjusted Net Revenues metric is not a measure in accordance with GAAP and is unaudited, Bonneville management believes the use and reporting of Adjusted Net Revenues assists in reflecting Bonneville's financial performance for day-to-day operations in applicable fiscal years. The Adjusted Net Revenues metric is 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 RELATED 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." As noted above, Net Billed Project debt expense is recorded over the term of the related outstanding debt. The Regional Cooperation Debt transactions in Fiscal Years 2014 through 2016 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 2016 absent the Fiscal Years 2014 through 2016 Regional Cooperation Debt management actions. The Adjusted Net Revenues metric also reflects the fact that Bonneville ceased financing the cost of energy efficiency measures with the proceeds of bonds issued to the United States Treasury, began expensing such costs in Fiscal Year 2016, and used debt management actions through the Regional Cooperation Debt initiative to lessen the near-term power rate impacts of the transition.

The effects of the foregoing debt management actions are not considered to be related to ongoing Federal System operations, and therefore management has determined that the Adjusted Net Revenues metric is a better representation of Federal System financial performance for the periods. End of Year Adjusted Net Revenues were \$143 million in Fiscal Year 2015 and negative \$31 million in Fiscal Year 2016. See "—Management Discussion of Operating Results—Fiscal Year 2016."

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 Discussion of Operating Results—Fiscal Year 2016." 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 2016, Bonneville had \$602 million in RAR and a \$750 million short-term credit facility (available to meet certain expenses) with the United States Treasury with no outstanding balance. 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 2018-2019,” and “—Fiscal Year 2017 Expectations and Related Information.” Depending on numerous variables, assumptions and forecasts, Bonneville may establish rates that, on average, will increase (or decrease) RAR for the relevant business line in the applicable rate period in amounts that are sufficient to meet Bonneville’s TPP policy. Bonneville measures RAR for both Power Services operations and Transmission Services operations.

Total Financial Reserves. “Total Financial Reserves” is a non-GAAP and unaudited metric that Bonneville uses to reflect current cash and cash equivalents. Bonneville uses the metric to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. Total Financial Reserves are composed of cash, cash equivalents, and special investments held in the Bonneville Fund, and 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 Year Fiscal Year 2016, Total Financial Reserves were \$724 million. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates for Fiscal Years 2018-2019” and “—Fiscal Year 2017 Expectations and Related Information.”

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 2012-2016
(Dollars in millions)**

Fiscal Year	Total Financial Reserves	Reserves Available for Risk	U.S. Treasury Short-Term Line	Days Liquidity on Hand⁽¹⁾
2012	\$1,022	\$704	\$750	319
2013	1,272	641	750	303
2014	1,224	784	750	317
2015	1,187	845	750	347
2016	724	602	750	281

⁽¹⁾ 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

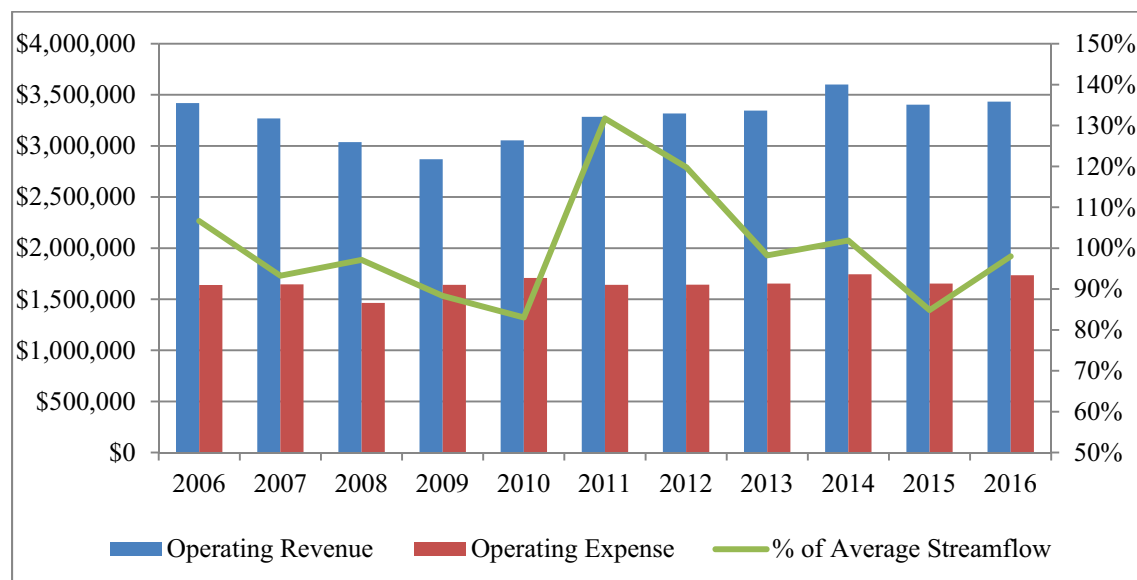
Streamflow is an important variable in Bonneville's financial performance because, in effect, it is the fuel for the hydroelectric facilities of the Federal System. The availability of hydroelectric generation affects Bonneville's purchased power costs. In periods of abundant hydroelectric generation 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 2016-2017 Rate Period, Bonneville assumed that revenues from net secondary sales would average approximately \$335 million per fiscal year of the rate period, assuming average streamflow. For reference, \$335 million is approximately ten percent of Bonneville total revenues of approximately \$3.4 billion (Fiscal Year 2016).

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 2016, Bonneville made \$34 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. Energy Northwest participates in certain retirement plans administered by the State of Washington. Contribution amounts are paid by Energy Northwest to the State of Washington and are recorded as an expense during the year in which the payment relates. In Fiscal Year 2016, Energy Northwest's total required pension contributions were \$14 million. While Energy Northwest's contributions represent its full current liability under such pension plans, any unfunded pension benefit obligations due to changes in the net pension liability could result in higher required contributions in future years.

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2014 through 2016 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.

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**Federal System Statement of Revenues and Expenses
(Unaudited)**

As of Sept. 30 – Dollars in millions	<u>2016</u>	<u>2015</u>	<u>2014</u>
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities ⁽¹⁾	\$2,070	\$1,929	\$1,945
Direct Service Industrial Customers	19	78	107
Northwest Investor-Owned Utilities	76	67	72
Sales outside the Northwest Region ⁽²⁾	238	326	448
Book-outs ⁽³⁾	<u>(22)</u>	<u>(45)</u>	<u>(38)</u>
Total Sales of Electric Power	2,381	2,355	2,534
Transmission ⁽⁴⁾	947	937	932
Fish Credits and other Revenues ⁽⁵⁾	<u>105</u>	<u>112</u>	<u>134</u>
Total Operating Revenues	3,433	3,404	3,600
Operating Expenses:			
Bonneville O&M ⁽⁶⁾	1,114	1,022	1,015
Purchased Power ⁽³⁾	112	76	199
Corps, Reclamation, and Fish & Wildlife Service O&M ⁽⁷⁾	402	381	356
Non-Federal entities O&M — net billed ⁽⁸⁾	254	314	292
Non-Federal entities O&M — non-net billed ⁽⁹⁾	<u>37</u>	<u>42</u>	<u>36</u>
Total Operation and Maintenance	1,919	1,835	1,898
Net billed Debt Service	240	219	344
Non-net billed Debt Service	<u>9</u>	<u>10</u>	<u>12</u>
Non-Federal Projects Debt Service ⁽¹⁰⁾	249	229	356
Federal Projects Depreciation	471	448	441
Residential Exchange ⁽¹¹⁾	<u>219</u>	<u>200</u>	<u>201</u>
Total Operating Expenses	<u>2,858</u>	<u>2,712</u>	<u>2,896</u>
Net Operating Revenues	<u>575</u>	<u>692</u>	<u>704</u>
Interest Expense:			
Appropriated Funds	203	217	236
Long-term debt	200	188	139
Capitalization Adjustment ⁽¹²⁾	(65)	(65)	(65)
Allowance for funds used during construction	<u>(40)</u>	<u>(53)</u>	<u>(50)</u>
Net Interest Expense ⁽¹³⁾	<u>298</u>	<u>287</u>	<u>260</u>
Net Revenues/(Expenses)	<u>\$277</u>	<u>\$405</u>	<u>\$444</u>
 Total Sales (annual average megawatts)			
(Net of Residential Exchange Program and excluding Canadian Entitlement Return)	9,642	9,315	10,197

⁽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 2016 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) 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 \$104 million, \$78 million, and \$73 million in Fiscal Years 2014, 2015, and 2016, 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 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 2016, the Residential Exchange Program payments were \$214 million. In Fiscal Year 2016, 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 Discussion of Operating Results

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. For additional details related to Fiscal Year 2016 Adjusted Net Revenues, see the end of this section and see “—Bonneville’s Use of Non-GAAP Financial Metrics.” 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. 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 2016 runoff volume at The Dalles Dam was 98 MAF. The full 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, a Canadian electric utility owned by the province of British Columbia.

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.

Adjusted Net Revenues is a metric that Bonneville uses to report net revenues after taking into account the effects of certain debt management actions under Regional Cooperation Debt. See “—Bonneville’s Use of Non-GAAP Financial Metrics.” Prior to Fiscal Year 2014, these actions included the Debt Optimization Program and beginning in Fiscal Year 2014, the actions have included (and will continue to include) more recent Regional Cooperation Debt actions. The effect on net revenues in Fiscal Year 2016 of the prior Debt Optimization Program was a reduction of \$7 million, with the effect of the more recent Regional Cooperation Debt transactions contributing \$387 million to Fiscal Year 2016 net revenues. In addition, Bonneville made a \$72 million revenue requirement adjustment to limit the upward power rate impacts of ceasing to capitalize energy conservation costs beginning in Fiscal Year 2016. Thus, after removing the combined effects of the Debt Optimization Program and the Fiscal Year 2016 Regional Cooperation Debt transaction and the revenue requirement adjustment, Bonneville reported Adjusted Net Revenues of negative \$31 million for Fiscal Year 2016. By contrast, as noted immediately above, net revenues were \$277 million in Fiscal Year 2016. Adjusted Net Revenues are described under “—Bonneville’s Use of Non-GAAP Financial Metrics,” and in the Management Discussion and Analysis in the Federal System Audited Financial Statements for the Year Ended September 30, 2016, included in Appendix B-1 to the Official Statement. See also “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.”

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.”

Fiscal Year 2015

In Fiscal Year 2015, Bonneville made its scheduled United States Treasury payments on time and in full for the 32nd consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of \$1.2 billion, which is a decline of approximately three percent from the prior fiscal year.

In Fiscal Year 2015, Federal System net revenues were \$405 million, a decrease of approximately \$39 million from net revenues of \$444 million in Fiscal Year 2014. For additional details related to Fiscal Year 2015 Adjusted Net Revenues, see the end of this section and see “—Bonneville’s Use of Non-GAAP Financial Metrics.”

For Fiscal Year 2015, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were \$3.3 billion, a decrease of approximately \$162 million from the prior fiscal year. Power Services’ gross sales decreased by \$173 million, or approximately seven percent, in Fiscal Year 2015 compared to Fiscal Year 2014 primarily due to two key factors: (i) firm power sales decreased \$48 million in Fiscal Year 2015 compared to Fiscal Year 2014 due to decreased load shaping revenue from the unseasonably warm weather in the Pacific Northwest and reduced revenue from DSIs resulting from the reduction in load commitment that went into effect in Fiscal Year 2015, and (ii) seasonal surplus (secondary) sales decreased \$125 million in Fiscal Year 2015 due to the low water year and lower production at Columbia Generating Station due to the scheduled biennial refueling outage. January through July 2015 runoff volume at The Dalles Dam was 84 MAF. The full Fiscal Year 2015 volume finished at 113 MAF, a decrease of 22 MAF from the 135 MAF attained in Fiscal Year 2014, and substantially below the historical average of 132 MAF.

Transmission Services gross sales increased \$11 million primarily due to \$18 million of revenue recorded in Fiscal Year 2015, of which \$14 million related to prior fiscal years, to reflect corrected amounts that should have been payable to Bonneville by certain customers for certain transmission services. In Fiscal Year 2015, Bonneville discovered that it had under-billed these customers by including in their transmission bills certain payment credits to which the customers were not entitled. This one-time revenue adjustment was determined to be immaterial to Fiscal

Year 2015 and prior periods. Partially offsetting the effects of the foregoing were lower short-term sales of transmission service caused by the implementation of new mandatory reliability standards.

Operating expense decreased approximately \$185 million in Fiscal Year 2015 from Fiscal Year 2014. Operations and maintenance expense increased \$58 million, or three percent, from the prior fiscal year primarily due to: (i) an increase of \$26 million in Fish and Wildlife spending for habitat restoration and mitigation projects and land acquisitions, (ii) an increase of \$20 million in Columbia Generating Station plant costs due to higher maintenance and costs related to biennial refueling in Fiscal Year 2015, (iii) an increase of \$19 million in transmission operations, maintenance and engineering costs primarily arising from additional substation and non-electric maintenance work, as well as increased work associated with control center and compliance-related activities, (iv) an increase of \$13 million in transmission acquisition and ancillary purchases caused principally by a \$9 million expense recorded in Fiscal Year 2015 related to oversupply events that occurred in Fiscal Year 2012 (the expense had previously been capitalized and recorded as a regulatory asset), and (v) an increase of \$7 million in hydro facilities operations and maintenance for the Corps largely due to the replacement of transformer bushings at Chief Joseph Dam, generator repairs at Bonneville Dam and head-gates refurbishment at McNary Dam. Partially offsetting these increases was an expense reduction in the amount of \$27 million from the reversal of a contingent liability originally established for the breach of contract claims associated with the California Refund Proceedings.

Purchased power expense, net of bookouts, decreased \$123 million from the prior fiscal year. The decrease in purchased power was driven principally by warmer weather in Bonneville's service territory and higher-than-typically-observed streamflow during a time of the year when Bonneville normally makes balancing power purchases (as noted above, Fiscal Year 2015 had dry conditions overall). This decreased the need for power purchases through the second quarter. In addition certain long-term, higher-priced power purchase contracts for winter hedging purposes expired. Also, under agreements with BC Hydro, Bonneville recorded credits to purchase power expense of \$16 million.

Net interest expense for Fiscal Year 2015 increased \$27 million, or ten percent, compared to Fiscal Year 2014, primarily due to the lapse of the effects of a one-time \$36 million interest saving in Fiscal Year 2014 arising from the early payment of United States Treasury bonds. Partially offsetting the effects of the foregoing was lower aggregate interest expense resulting from Regional Cooperation Debt management actions in Fiscal Year 2014. These actions enabled the prepayment of comparatively high interest-rate Federal Appropriations Repayment Obligations at the end of Fiscal Year 2014, thereby reducing interest expense for Federal Appropriations Repayment Obligations in Fiscal Year, 2015. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

Non-Federal Projects Debt Service expense decreased \$127 million, or 36 percent, from the prior fiscal year, primarily due to the debt management actions with respect to Regional Cooperation Debt to extend bond maturities. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions."

Depreciation and amortization expense increased \$7 million, or two percent, from the prior fiscal year, primarily due to increased completed plant in service for Power Services construction projects and for Transmission Services lease-purchased transmission facilities.

Adjusted Net Revenues is a metric that Bonneville uses to report net revenues after taking into account the effects of certain debt management actions under Regional Cooperation Debt. See "—Bonneville's Use of Non-GAAP Financial Metrics." Prior to Fiscal Year 2014, these actions included the Debt Optimization Program and beginning in Fiscal Year 2014, the actions have included (and will continue to include) more recent Regional Cooperation Debt actions. The effect on net revenues in Fiscal Year 2015 of the prior Debt Optimization Program was a reduction of \$7 million, with the effect of the more recent Regional Cooperation Debt transactions contributing \$269 million to Fiscal Year 2015 net revenues. Thus, after removing the combined effects of the Debt Optimization Program and the Fiscal Year 2015 Regional Cooperation Debt transaction, Adjusted Net Revenues were \$143 million in Fiscal Year 2015. By contrast, as noted immediately above, net revenues were \$405 million in Fiscal Year 2015. Adjusted Net Revenues are described under "—Bonneville's Use of Non-GAAP Financial Metrics," and in the Management Discussion and Analysis in the Federal System Audited Financial Statements for

the Year Ended September 30, 2015, included in Appendix B-1 to the Official Statement. See also “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.”

At the end of Fiscal Year 2015, RAR for Power Services operations was \$395 million, an increase of 45 percent from the prior fiscal year, and RAR for Transmission Services operations was \$450 million, a decrease of 12 percent from the prior fiscal year. Aggregate Bonneville RAR was \$845 million, an increase of eight percent from the prior fiscal year. See “—Bonneville’s Use of Non-GAAP Financial Metrics.”

Fiscal Year 2014

In Fiscal Year 2014, Bonneville made its scheduled United States Treasury payments on time and in full for the 31st consecutive year. Bonneville finished Fiscal Year 2014 with Total Financial Reserves of \$1.2 billion, which is a decrease of approximately four percent from the prior fiscal year.

In Fiscal Year 2014, Federal System net revenues were \$444 million, an improvement of approximately \$548 million from net revenues of negative \$105 million in Fiscal Year 2013. For additional details related to Fiscal Year 2014 Adjusted Net Revenues, see the end of this section and see “—Bonneville’s Use of Non-GAAP Financial Metrics.”

For Fiscal Year 2014, Power Services and Transmission Services consolidated gross sales increased by approximately \$223 million from the prior fiscal year. Power Services’ gross sales increased \$134 million, or approximately five percent, primarily due to two key factors: (i) firm power sales increased \$118 million, or six percent, in Fiscal Year 2014 compared to Fiscal Year 2013 due to the nine percent average power rate increase which took effect beginning October 1, 2013 and higher Preference Customer peak loads due to colder than average temperatures in October 2013, December 2013 and February 2014, and (ii) seasonal surplus (secondary) sales increased \$16 million in Fiscal Year 2014 compared to Fiscal Year 2013 due to slightly higher market prices and increased streamflow compared to the prior year. January through July 2014 runoff volume at The Dalles Dam was 108 MAF. The full Fiscal Year 2014 volume finished at 135 MAF, an increase from 130 MAF in Fiscal Year 2013, and close to the historical average of 133 MAF.

Transmission Services gross sales increased \$89 million, or 11 percent, mainly due to the 11 percent average transmission rate increase which took effect beginning October 1, 2013.

Transmission miscellaneous revenues decreased by \$15 million, or 27 percent, mainly due to higher Fiscal Year 2013 reimbursable activity from other federal agencies for assistance Bonneville provided in the aftermath of Hurricane Sandy and a one-time effect from the receipt of revenues in Fiscal Year 2013 for the termination/expiration of certain transmission service that Bonneville theretofore had provided on comparatively favorable terms to the related customers (referred to by Bonneville as “Precedent Transmission Service Agreements”).

Operating expense decreased approximately \$264 million in Fiscal Year 2014 from Fiscal Year 2013. Operations and maintenance increased \$57 million, or three percent, from the prior fiscal year primarily due to: (i) a \$30 million increase in transmission maintenance and operation costs arising from increased reliability compliance activities, upgrades to Federal Transmission System communication systems, and additional labor costs for increased control center, substation, and transmission line maintenance, (ii) a \$27 million increase in decommissioning expense due to the one-time only credit received in Fiscal Year 2013 for a settlement related to spent nuclear fuel storage costs at the terminated Trojan nuclear facility, (iii) a \$26 million increase due to increased reliability compliance activities for Federal System Hydroelectric Projects, and (iv) a \$16 million increase in general and administrative costs related to support of information technology and infrastructure. These increases were offset in part by a \$32 million reduction in Columbia Generating Station costs reflecting the fact that Fiscal Year 2014 was not a refueling year and Fiscal Year 2013 was a refueling year (refueling work results in higher maintenance costs). Bonneville also reduced expenditures on the Fish and Wildlife program by \$7 million, and power marketing and business support and transmission reimbursable programs by \$9 million.

Purchased power expense increased \$45 million, or 29 percent, from the prior fiscal year. The increase in purchased power was driven mainly by lower year-over-year hydroelectric generation (despite slightly increased streamflow) and reduced output of the Grand Coulee Dam due to reduced turbine capacity during scheduled renewal of certain facilities in Fiscal Year 2014. Net interest expense for Fiscal Year 2014 decreased \$30 million, or ten percent, compared to Fiscal Year 2013, primarily due to a non-cash gain on extinguishment of debt related to amounts borrowed from the United States Treasury, as further described in Appendix B-1 (Note 7 to Financial Statements).

Non-Federal Projects Debt Service expense decreased \$377 million, or 51 percent, from the prior fiscal year, primarily due to the debt management actions with respect to the Net Billed Bonds to extend bond maturities. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.”

Depreciation and amortization expense increased \$11 million, or three percent, from the prior fiscal year, primarily due to increased completed plant in service for Power Services construction projects and for Transmission Services lease-purchased transmission facilities.

Adjusted Net Revenues were \$236 million in Fiscal Year 2014, which was an increase of \$180 million from Bonneville’s Adjusted Net Revenues of \$56 million in Fiscal Year 2013. By contrast, as noted immediately above, net revenues were \$444 million in Fiscal Year 2014. At the end of Fiscal Year 2014, RAR for Power Services operations was \$273 million, an increase of 50 percent from the prior fiscal year, and RAR for Transmission Services operations was \$511 million, an increase of 11 percent from the prior fiscal year. Aggregate Bonneville RAR was \$784 million, an increase of 22 percent from the prior fiscal year. Adjusted Net Revenues and RAR are described in “—Bonneville’s Use of Non-GAAP Financial Metrics.”

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.

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

As of Sept. 30 – Dollars in millions	<u>2016</u>	<u>2015</u>	<u>2014</u>
Total Operating Revenues	\$3,433	\$3,404	\$3,600
Less: Operating Expenses ⁽¹⁾	<u>1,735</u>	<u>1,654</u>	<u>1,744</u>
Net Funds Available to meet Non-Federal Debt Service Obligations	1,698	1,750	1,856
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects ⁽²⁾	249	228	355
Lease-Purchase Program ⁽³⁾	52	47	39
Electric Power Prepayments ⁽⁴⁾	<u>31</u>	<u>31</u>	<u>31</u>
Total Non-Federal Debt Service Obligations	<u>332</u>	<u>306</u>	<u>425</u>
Revenue Available for Treasury	1,366	1,444	1,431
Amount Allocated for Payment to Treasury ⁽⁵⁾ :			
Corps and Reclamation O&M ⁽⁶⁾	402	381	356
Net Interest Expense ⁽⁷⁾	298	287	260
Lease-Purchase Program ⁽³⁾	(52)	(47)	(39)
Electric Power Prepayments ⁽⁴⁾	(13)	(14)	(15)
Capitalization Adjustment ⁽⁸⁾	65	65	65
Allowance for Funds Used During Construction ⁽⁹⁾	17	24	22
Amortization of Federal Principal ⁽¹⁰⁾	<u>1,437</u>	<u>449</u>	<u>567</u>
Total Amount Allocated for Payment to Treasury ⁽⁵⁾	2,154	1,145	1,216
Non-Federal Debt Service Coverage Ratio ⁽¹¹⁾	5.1x	5.7x	4.4x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio ⁽¹²⁾	1.7x	1.7x	1.7x

(1) Operating Expenses include the following items from the Federal System Statement of Revenues and Expenses: Bonneville O&M, Purchased Power, Book-outs, 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 \$12 million, \$10 million, and \$9 million for Fiscal Years 2014, 2015, and 2016 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 2016, Bonneville provided credits on Preference Customers' bills in an aggregate amount of \$31 million. Of this amount, \$14 million is accounted for as Net Interest Expense and \$17 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 2014, 2015, and 2016 were \$991 million, \$891 million, and \$1.9 billion respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation, and Fish and Wildlife Service as portrayed under "Corps and Reclamation O&M." See "—Direct Funding of Federal System Operations and Maintenance Expense."
- (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 2014, 2015, and 2016. 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, 2015 and 2016 due to Non-Federal Debt management actions including Regional Cooperation Debt. Regional Cooperation Debt actions enabled Bonneville to prepay \$959 million in high-interest rate Federal Appropriations Repayment Obligations in Fiscal Year 2016, \$229 million in Fiscal Year 2015, and \$321 million in Fiscal Year 2014, 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:

Total Operating Revenues-Operating Expense (Footnote 1)

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

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

Total Operating Revenues

Operating Expense (Footnote 1) + Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments

(The Non-Federal Debt Service plus Operating Expense Coverage Ratio increased in Fiscal Years 2014-2016 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 2014-2016 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 Discussion of Unaudited Results for the Nine Months ended June 30, 2017

Total operating revenues were \$2.7 billion through the third quarter of Fiscal Year 2017 (“Fiscal Year 2017 Third Quarter”), an increase of \$104 million as compared to operating revenues for the nine months ended June 30, 2016 (“Fiscal Year 2016 Third Quarter”). Consolidated gross sales for Power and Transmission Services, including the effect of bookouts, increased \$124 million through Fiscal Year 2017 Third Quarter compared to consolidated gross sales through Fiscal Year 2016 Third 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 increased \$106 million through Fiscal Year 2017 Third Quarter as compared to Fiscal Year 2016 Third Quarter. Firm power sales increased by \$34 million primarily due to increased load shaping charges related to increased power sales due to colder than average weather experienced in Fiscal Year 2017 and higher DSI sales. Surplus power sales increased \$72 million mainly due to increased streamflows and slightly higher energy prices that Bonneville was able to obtain for the sale of surplus firm power and seasonal surplus (secondary) energy. United States Treasury credits for fish and wildlife mitigation decreased \$13 million due to increased streamflows and higher federal generation.

Transmission Services gross sales increased \$13 million through Fiscal Year 2017 Third Quarter as compared to Fiscal Year 2016 Third Quarter primarily due to increased short-term transmission sales related to the increase in streamflows and higher federal generation as described immediately above.

Through Fiscal Year 2017 Third Quarter, total operating expenses were \$2.2 billion, a \$96 million increase when compared to Fiscal Year 2016 Third Quarter. Operations and maintenance expense increased \$112 million primarily due to: (i) a \$85 million increase in Columbia Generating Station plant costs since Fiscal Year 2017 is a refueling year, (ii) a \$15 million increase in third party wheeling costs for delivering energy to transfer service customers, and (iii) a \$23 million increase in Reclamation operations and maintenance costs primarily due to additional work performed in Fiscal Year 2017 and the ongoing mechanical overhaul of generating equipment at the Grand Coulee Dam Third Power Plant. During the same period in Fiscal Year 2016, other work was delayed at Grand Coulee, which had the comparative impact of increasing current year expense. These increases were offset by a \$17 million decrease in corporate overhead costs primarily due to: (i) cost management initiatives and (ii) lower payments for post-retirement benefit programs.

Non-Federal Debt Service decreased \$26 million through Fiscal Year 2017 Third Quarter as compared to Fiscal Year 2016 Third Quarter, primarily due to the debt management actions with respect to Regional Cooperation Debt. See “CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Regional Cooperation Debt and Related Actions.”

Depreciation and amortization increased \$13 million primarily due to increased completed plant in service for Power Services and Transmission Services.

For further information regarding Fiscal Year 2017 Third Quarter unaudited results, see Appendix B-2—“FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE NINE MONTHS ENDED JUNE 30, 2017.”

BONNEVILLE LITIGATION

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

Columbia River ESA Litigation

In a lawsuit filed May 4, 2001, in the Oregon Federal District Court, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Columbia River System Biological Opinion was arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NOAA Fisheries to

reinitiate consultation with the Action Agencies responsible for operation of the Federal System Hydroelectric Projects and to prepare a new biological opinion.

In May 2003, the Oregon Federal District Court ruled that the 2000 Biological Opinion was inadequate because it relied on offsite mitigation measures that were “not reasonably certain to occur” and because the biological opinion used an “action area” that was too small. (An “action area” is the geographically delineated area comprising where the dams’ operations directly or indirectly affect ESA-listed species.) In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court.

On November 30, 2004, NOAA Fisheries finalized a subsequent biological opinion (the “2004 Biological Opinion”) to replace the 2000 Biological Opinion and address the deficiencies identified by the Oregon Federal District Court. Plaintiffs filed a complaint against NOAA Fisheries and subsequently filed another complaint against the Corps and Reclamation with the Oregon Federal District Court alleging that the 2004 Biological Opinion and the Corps’ and Reclamation’s decisions to implement the 2004 Biological Opinion violated certain provisions of the ESA and Administrative Procedure Act. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The court issued an order remanding the matter to the federal agencies to correct identified deficiencies. Additionally, in the court’s remand order, the federal agencies were ordered to undertake collaboration with the sovereign parties to the litigation (states and tribes) to address key issues in a new biological opinion. The federal government and the State of Idaho appealed the order to the Ninth Circuit Court, which ultimately upheld the order.

On May 5, 2008, NOAA Fisheries issued its 2008 Columbia River System Biological Opinion. On August 12, 2008, Bonneville issued its record of decision adopting the actions in the 2008 Columbia River System Biological Opinion. A number of parties filed litigation in the Oregon Federal District Court in connection with the 2008 Columbia River System Biological Opinion naming NOAA Fisheries, the Corps and Reclamation as defendants and alleging violations of the ESA as well as the CWA. In addition, some interests filed litigation in the Ninth Circuit Court against Bonneville regarding the 2008 Columbia River System Biological Opinion. The Ninth Circuit Court has exclusive direct review jurisdiction over most of Bonneville’s administrative actions.

In September 2009, the federal agencies filed an “Adaptive Management Implementation Plan” with the court, in which the federal agencies outlined a more detailed and aggressive plan for implementing the adaptive management provisions of the 2008 Columbia River System Biological Opinion. In May 2010, NOAA Fisheries finalized a “2010 Supplemental Columbia River System Biological Opinion” to supplement the existing 2008 Columbia River System Biological Opinion and to incorporate the Adaptive Management Implementation Plan. In August 2011, the Oregon Federal District Court found that the 2010 Supplemental Columbia River System Biological Opinion was unlawful because it had not identified specific mitigation plans after 2013, and it ordered NOAA Fisheries to issue a new or supplemental Columbia River System Biological Opinion that corrects this deficiency.

In January 2014, NOAA Fisheries issued the 2014 Columbia River System Supplemental Biological Opinion. In February 2014, Bonneville, the Corps and Reclamation 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 federal 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 Oregon Federal 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 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,” and “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The National Environmental Policy Act and the Endangered Species Act.”

On June 3, 2016, the federal government submitted to the Oregon Federal District Court a proposed schedule for preparing the environmental impact statement and stated that “to complete a system-wide, comprehensive environmental impact statement . . . will require a minimum of five years.” With respect to the integration of the process of the new environmental impact statement and the new biological opinion the federal government’s June 3 filing stated that “the Federal Defendants are not presently in a position to precisely delineate how the processes will be coordinated and sequenced.”

The plaintiffs filed a response on June 17, 2016 and on July 1, 2016, the federal government and various aligned parties filed replies to the plaintiffs’ response. On July 6, 2016, the Oregon Federal District Court issued an order directing that a new environmental impact statement under NEPA be prepared by 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. The court also granted the federal government’s request to extend the deadline for a new biological opinion to December 31, 2018. See “POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The National Environmental Policy Act and the Endangered Species Act.”

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,” and “POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville’s Power Services—Fish and Wildlife—The National Environmental Policy Act and the Endangered Species Act.”

The United States has decided not to appeal the ruling and all protective notices of appeal were dismissed on December 12, 2016. 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. A hearing on the matter was held on March 9, 2017, and on March 27, 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.

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 May 1, 2017, the parties filed a joint proposed schedule for periodic status conferences and a process for developing a proposed spill plan, which the court adopted in an order dated May 10, 2017. The parties filed a joint status report with the court on June 15, 2017, and the first status conference was held August 2, 2017, with a second conference to be held on October 3, 2017. The court has been advised through the federal government’s briefing that, should the parties fail to reach agreement on a spring 2018 spill plan forcing the court to decide, a decision at least several weeks prior to the beginning of the spill season on April 1, 2018 is optimal.

Finally, the Oregon Federal District Court declined plaintiffs’ request to alter the adaptive management decision making process for implementing in-season changes to system operations “at this time” for lack of evidence that the current system is not working. The Oregon Federal District Court nevertheless directed the parties to confer on

whether any changes to the “adaptive management system” are appropriate and invited motion practice in the future if any party “has evidence the current system is not working.”

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 within 14 days 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. 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 plaintiffs are seeking an order to compel EPA to produce a Total Maximum Daily Allowance for temperature in the Columbia and Snake Rivers in Oregon and Washington within one year from their filing (February 23, 2017), as well as other injunctive relief that the plaintiffs may seek during the pendency of the case. 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 will make a settlement payment of \$28.5 million plus interest to SCE in exchange for SCE’s dismissing the two claims. Payment by Bonneville is due (with interest) when it receives a final resolution of its refund liability, if any, in the California refund proceedings. It is possible that the California refund proceedings may end soon. See “—Litigation and Related Disputes Arising from the West Coast Power 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 Power 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.

In the "FERC California Refund Docket" FERC is examining, among other things, whether to order refunds from entities that sold power into California power markets in 2000 and 2001. More particularly, FERC is examining 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 a market-clearing auction, power sellers' bids are accepted from lowest to highest price until all power demand is met, and accepted bids are all paid the same price as the bid for the last unit of electricity needed to meet total demand (the highest price that 'clears the market'). The Cal-ISO also entered into non-market-clearing power purchases and exchanges to obtain electric power to meet loads.

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 cannot 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, as described below.

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 will not become payable until the FERC California Refund Docket is 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. These claims are referred to herein as the "California Breach Claims." The California Parties also sought to recover pre-judgment and post-judgment interest and litigation costs in the California Breach Claims litigation. Bonneville estimates that the aggregate refund period contract damages claimed by California Parties are approximately \$41 million in specified damages (not including litigation costs and interest) plus additional unspecified amounts that could be realized through declaratory orders sought by the California Parties.

The California Parties' claims in the California Breach Claims litigation are 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. In a May 2012 order (the "May 2012 CFC Order"), the Court of Federal Claims found that when FERC established mitigated market prices in the Cal-ISO and Cal-PX markets to calculate refunds for transacting entities that were subject to FERC's refund authority (as noted above, Bonneville was not subject to FERC's refund authority for such transactions as established in the September 2005 Ninth Circuit Court Opinion), FERC had "retroactively reset" the tariff rates in such markets. The Court of Federal Claims also found that FERC's retroactive revision of tariff rates retroactively adjusted Bonneville's contracted-for prices to an amount equal to the 'new' lower tariff rates and that Bonneville breached contracts with the California Parties by failing to pay refunds for amounts it retained in excess of the mitigated market-clearing prices. The Court of Federal Claims also found that Bonneville is liable for contract damages in the amount of the difference between the original contracted-for

prices and the FERC-revised prices, as established by FERC in the FERC California Refund Docket. (As described below, the May 2012 CFC Order was set aside in December 2013 by a new judge in the California Breach Claims litigation and she has indicated she intends to dismiss the California Breach Claims.)

In September 2012, the Ninth Circuit Court, in further review of the FERC California Refund Docket, issued an opinion holding that FERC, in establishing mitigated prices in the Cal-PX and Cal-ISO markets for calculating refunds, had not retroactively reset the tariff rates in those markets (the “September 2012 Ninth Circuit Court Opinion”). The Ninth Circuit Court found that although “FERC has authority to state retroactively what a ‘just and reasonable’ rate would have been pursuant to its refund authority, Congress did not provide FERC with retroactive rate setting authority over non-jurisdictional sellers” like Bonneville.

As part of the FERC California Refund Docket, an administrative law judge (“FERC ALJ”) appointed by the FERC Commissioners made certain findings related to (i) the Summer 2000 Transactions, and (ii) certain non-cleared (bi-lateral) multi-day power sales and power exchange transactions by Bonneville into the Cal-ISO’s “Exchange and Multi-day” markets in 2000 and 2001 (“Exchange and Multi-day Transactions”). In February 2013, the FERC ALJ issued these findings to the FERC Commissioners (the “February 2013 Findings”).

Following the issuance of the February 2013 Findings, Bonneville filed a brief with the FERC Commissioners arguing, among other things, that under the September 2005 Ninth Circuit Court Opinion and the September 2012 Ninth Circuit Court Opinion, FERC does not have authority to order refunds by non-jurisdictional utilities such as Bonneville or to modify Bonneville’s rates. On November 10, 2014, FERC dismissed Bonneville from the proceeding with no finding of any tariff violation.

In certain orders issued in April 2013 (the “April 2013 CFC Orders”), the Court of Federal Claims rejected a motion by the United States Department of Justice on behalf of Bonneville and another federal power marketing administration asking the court to reconsider its May 2012 CFC Order on liability in light of the Ninth Circuit Court’s September 2012 ruling that FERC had not retroactively reset tariff rates. (The Ninth Circuit’s September 2012 ruling is referred to herein as the City of Redding Opinion.) The Court of Federal Claims ruled that the City of Redding Opinion was not dispositive of the contract liability issue in the California Breach Claims litigation because the Ninth Circuit Court did not address how the FERC-mitigated prices affected the California Parties’ breach of contract claims against Bonneville. The Court of Federal Claims also determined, in response to motions by the California Parties, that if and when FERC resets prices, Bonneville will be contractually bound to refund the value, in excess of FERC-mitigated prices, that Bonneville received from the Cal-ISO, Cal-PX, and others in the Summer 2000 Transactions and the Exchange and Multi-day Transactions (which were under review by FERC in the FERC California Refund Docket described above).

In the spring of 2013, a new Court of Federal Claims judge was assigned to the California Breach Claims case. On December 20, 2013, the new judge issued an order vacating the prior judge’s substantive orders, including the April 2013 CFC Order and the May 2012 CFC Order. On February 26, 2014, the judge issued a notice to show cause why the court, on reconsideration, should not dismiss these cases, because of plaintiffs’ failure to establish the requirements of standing to sue on a government contract, thereby depriving the court of jurisdiction of the case. Oral argument was held on June 5, 2014 and January 22, 2015. At the judge’s request, Bonneville filed a motion to dismiss the California Breach Claims. On March 12, 2015, the judge issued an order granting Bonneville’s motion to dismiss, and holding that the California Parties lacked standing to sue because no contractual privity existed between Bonneville and the California Parties. The judge also found that even if the California Parties had standing, the breach of contract claims should nevertheless be dismissed because the factual predicate for a breach of contract claim against Bonneville did not exist. The California Parties appealed the decision to the United States Court of Appeals for the Federal Circuit, and filed their initial brief on September 8, 2015. In the initial brief, the California Parties raised the following three issues: (i) the decision to vacate the May 2012 CFC Order was an abuse of discretion; (ii) contractual privity existed between Bonneville and the California Parties; and (iii) a factual predicate for a breach of contract claim against Bonneville to pay refunds existed. On October 3, 2016, the Federal Circuit Court of Appeals affirmed the Court of Federal Claims dismissal of all breach of contract claims. The Plaintiffs filed for reconsideration and rehearing en banc on November 17, 2016. The court denied the Plaintiffs’ motions on February 6, 2017 and the court’s mandate was issued on February 13, 2017. On July 6, 2017, the California Parties filed a Petition for a Writ of Certiorari with the United States Supreme Court. Bonneville has until September 11, 2017 to file a response.

For a description of litigation between SCE and Bonneville arising out of developments in West Coast energy markets in 1999-2001, see “—Southern California Edison v. Bonneville Power Administration.”

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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APPENDIX B-1

**FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS
FOR THE YEARS ENDED SEPTEMBER 30, 2016, 2015 AND 2014**

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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 which comprise the combined balance sheets as of September 30, 2016 and 2015 and the related combined statements of revenues and expenses and cash flows for each of the three years in the period ended September 30, 2016.

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, 2016 and September 30, 2015, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2016 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

October 28, 2016

PricewaterhouseCoopers LLP, 805 SW Broadway, Suite 800, Portland, OR 97205-3344
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Federal Columbia River Power System

Combined Balance Sheets

As of September 30

(Millions of Dollars)

	2016	2015
Assets		
Utility plant		
Completed plant	\$ 18,276.5	\$ 17,235.7
Accumulated depreciation	(6,310.4)	(6,192.7)
Net completed plant	11,966.1	11,043.0
Construction work in progress	1,312.0	1,815.7
Net utility plant	13,278.1	12,858.7
Nonfederal generation	3,504.8	3,534.2
Current assets		
Cash and cash equivalents	579.6	646.7
Short-term investments in U.S. Treasury securities	272.9	694.3
Accounts receivable, net of allowance	50.5	35.7
Accrued unbilled revenues	279.8	298.9
Materials and supplies, at average cost	111.9	116.9
Prepaid expenses	31.8	27.4
Total current assets	1,326.5	1,819.9
Other assets		
Regulatory assets	6,180.2	6,603.2
Nonfederal nuclear decommissioning trusts	314.3	282.7
Deferred charges and other	293.8	449.9
Total other assets	6,788.3	7,335.8
Total assets	\$ 24,897.7	\$ 25,548.6

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)

	2016	2015
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	\$ 3,392.6	\$ 3,175.7
Debt		
Federal appropriations	2,866.9	3,901.7
Borrowings from U.S. Treasury	4,682.6	4,366.7
Nonfederal debt	7,158.2	6,786.9
Total capitalization and long-term liabilities	18,100.3	18,231.0
 Commitments and contingencies (Note 13)		
 Current liabilities		
Debt		
Borrowings from U.S. Treasury	76.1	282.0
Nonfederal debt	857.6	752.5
Accounts payable and other	437.2	539.8
Total current liabilities	1,370.9	1,574.3
 Other liabilities		
Regulatory liabilities	2,143.8	2,259.8
IOU exchange benefits	2,551.9	2,683.9
Asset retirement obligations	185.7	184.8
Deferred credits and other	545.1	614.8
Total other liabilities	5,426.5	5,743.3
 Total capitalization and liabilities	\$ 24,897.7	\$ 25,548.6

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)

	2016	2015	2014
Operating revenues			
Sales	\$ 3,283.5	\$ 3,257.5	\$ 3,426.5
U.S. Treasury credits	77.2	82.3	108.5
Miscellaneous revenues	71.9	64.6	65.3
Total operating revenues	3,432.6	3,404.4	3,600.3
Operating expenses			
Operations and maintenance	2,025.3	1,959.2	1,901.3
Purchased power	111.7	76.3	199.1
Nonfederal projects	249.2	229.0	355.8
Depreciation and amortization	471.1	448.0	440.5
Total operating expenses	2,857.3	2,712.5	2,896.7
Net operating revenues	575.3	691.9	703.6
Interest expense and (income)			
Interest expense	353.8	355.7	333.7
Allowance for funds used during construction	(40.3)	(53.2)	(50.2)
Interest income	(15.4)	(15.3)	(23.4)
Net interest expense	298.1	287.2	260.1
Net revenues	\$ 277.2	\$ 404.7	\$ 443.5
Accumulated net revenues, beginning of year	3,175.7	2,823.1	2,432.2
Irrigation assistance	(60.3)	(52.1)	(52.6)
Accumulated net revenues, end of year	\$ 3,392.6	\$ 3,175.7	\$ 2,823.1

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)

	2016	2015	2014
Cash flows from operating activities			
Net revenues	\$ 277.2	\$ 404.7	\$ 443.5
Non-cash items:			
Depreciation and amortization	471.1	448.0	440.5
Amortization of nonfederal projects	25.9	23.1	119.2
Deferred payments for Energy Northwest-related O&M and interest	259.0	-	-
Gain on extinguishment of U.S. Treasury bonds	-	-	(36.1)
Changes in:			
Receivables and unbilled revenues	8.3	(22.6)	(14.8)
Materials and supplies	5.0	(4.4)	(0.4)
Prepaid expenses	(4.4)	5.0	8.0
Accounts payable and other	(92.5)	(1.1)	35.6
Regulatory assets and liabilities	65.0	16.6	(95.5)
IOU exchange benefits	(132.0)	(111.6)	(197.3)
Other assets and liabilities	(27.8)	(82.0)	(5.1)
Net cash provided by operating activities	854.8	675.7	697.6
Cash flows from investing activities			
Investment in utility plant, including AFUDC	(808.3)	(964.5)	(843.0)
U.S. Treasury securities:			
Purchases	(939.0)	(1,323.0)	(950.0)
Maturities	1,356.9	1,185.2	808.4
Deposits to nonfederal nuclear decommissioning trusts	(3.5)	(3.4)	(3.2)
Lease-purchase trust funds:			
Deposits to	(90.6)	(205.8)	(519.0)
Receipts from	219.1	205.2	256.8
Net cash used for investing activities	(265.4)	(1,106.3)	(1,250.0)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	83.0	48.0	119.7
Repayment	(1,117.8)	(236.3)	(321.1)
Borrowings from U.S. Treasury:			
Proceeds	429.0	619.0	603.0
Repayment	(319.0)	(212.3)	(206.9)
Nonfederal debt:			
Proceeds	411.6	206.2	520.1
Repayment	(49.6)	(121.7)	(227.0)
Customers:			
Net advances for construction	5.1	4.0	3.7
Repayment of funds used for construction	(38.5)	(36.7)	(37.4)
Irrigation assistance	(60.3)	(52.1)	(52.6)
Net cash (used for) and provided by financing activities	(656.5)	218.1	401.5
Net decrease in cash and cash equivalents	\$ (67.1)	\$ (212.5)	\$ (150.9)
Cash and cash equivalents at beginning of year	646.7	859.2	1,010.1
Cash and cash equivalents at end of year	\$ 579.6	\$ 646.7	\$ 859.2
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	\$ 376.2	\$ 365.8	\$ 350.7
Significant noncash investing and financing activities:			
U.S. Treasury bonds repaid with non-cash gains	\$ -	\$ -	\$ (39.1)
Nonfederal debt increase for Energy Northwest	\$ 320.7	\$ 572.8	\$ 221.6
Nonfederal debt extinguished through refinancing for Energy Northwest	\$ (217.9)	\$ (359.7)	\$ (112.0)
Other nonfederal	\$ 11.6	\$ 2.3	\$ -

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), the accounts of the Pacific Northwest generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) as well as the operations and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan facilities. Consolidated with BPA are “special purpose corporations” known as Northwest Infrastructure Financing Corporations (NIFCs), 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 Corps 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 Corps 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.

Reclassifications

Certain prior year balances in the Notes to Financial Statements have been reclassified to conform with the current presentation. These reclassifications had no effect on prior year FCRPS combined results of operations, financial condition, or cash flows.

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, 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. 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 primarily 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 Corps and Reclamation construction funded by congressional appropriations. The BPA rate is determined based on the weighted-average cost of borrowing for BPA and for the Lease-Purchase Program. (See discussion of the Lease-Purchase Program in Note 7, Debt and Appropriations.) The rate for appropriated funds is provided each year to BPA by the U.S. Treasury. (See Note 2, Utility Plant.)

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 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 total project cash funding requirements. The Nonfederal generation assets in the Combined Balance Sheets are amortized over the term of the related outstanding nonfederal debt, with the amortization expense included in Nonfederal projects on 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 Corps and Reclamation related to the FCRPS. Cash in the Bonneville Fund includes cash and 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 2016, 2015 and 2014, 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 unless the contract is 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 FCRPS 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. 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 credit 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. 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 is recognized over the terms of the related outstanding debt.

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 and gains, if any, related to the repayment of certain U.S. Treasury bonds considered extinguished or modified after being called and reissued. 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 balances in the Bonneville Fund including market-based special securities and interest earnings from other sources. Through Sept. 30, 2016, BPA continued to earn 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. Interest earnings on U.S. Treasury market-based special investments are based on the stated rates of the individual securities. BPA will no longer earn interest offset credits in fiscal year 2017. (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. On April 1, 2015, the FASB proposed to defer the effective date of the new revenue standard by one year and to permit one year early adoption. In 2016, the FASB issued three updates to the guidance. Management is evaluating the impact of adopting this guidance, which will be effective for fiscal year 2019.

Fees paid in cloud computing arrangements

In April 2015, the FASB issued an ASU addressing customer's accounting for fees paid in a cloud computing arrangement. Existing GAAP does not include explicit guidance about these types of fees. Examples of cloud computing arrangements include software as a service, platform as a service, infrastructure as a service, and other similar hosting arrangements. BPA does not expect any significant impact to the FCRPS financial statements as a result of adopting this guidance, which will be effective for fiscal year 2017.

Presentation of debt issuance costs

In April 2015, the FASB issued an ASU to align the balance sheet presentation of debt issuance costs with that of debt premiums and discounts. BPA does not expect any significant impact to the FCRPS financial statements as a result of adopting the guidance, which will be effective for fiscal year 2017.

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. Among other provisions, the ASU supersedes guidance to classify equity securities into trading or available-for-sale and requires all equity securities to be measured at fair value with changes in fair value recognized through net income. Management is evaluating the impact of adopting this guidance, which will be effective for 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 lease liabilities by lessees for those agreements classified as operating leases under current GAAP. Management is evaluating the impact of adopting this guidance, which will be effective for 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 for fiscal year 2022.

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 for fiscal year 2020.

SUBSEQUENT EVENTS

Management has performed an evaluation of events and transactions for potential FCRPS recognition or disclosure through Oct. 28, 2016, which is the date the financial statements were issued.

2. Utility Plant

<i>As of Sept. 30 — millions of dollars</i>	2016	2015	Estimated average service lives
Completed plant			
Federal system hydro generation assets	\$ 8,964.4	\$ 8,838.7	75 years
Transmission assets	9,088.9	8,217.7	48 years
Other assets	223.2	179.3	6 years
Completed plant	\$ 18,276.5	\$17,235.7	
Accumulated depreciation			
Federal system hydro generation assets	\$ (3,235.1)	\$(3,116.3)	
Transmission assets	(2,963.5)	(2,982.9)	
Other assets	(111.8)	(93.5)	
Accumulated depreciation	\$ (6,310.4)	\$(6,192.7)	
Construction work in progress			
Federal system hydro generation assets	\$ 485.3	\$ 399.6	
Transmission assets	800.6	1,348.1	
Other assets	26.1	68.0	
Construction work in progress	\$ 1,312.0	\$ 1,815.7	
Net Utility Plant	\$ 13,278.1	\$12,858.7	

Allowance for funds used during construction

<i>Fiscal year</i>	2016	2015	2014
BPA rate	3.0%	3.1%	3.7%
Appropriated rate	0.4%	0.1%	0.1%

Completed plant assets reported as transmission capital leased assets were \$1,285.6 million and \$548.2 million, with accumulated depreciation of \$45.4 million and \$54.2 million, at Sept. 30, 2016, and 2015, respectively.

Construction work in progress includes \$118.7 million of transmission assets related to a new transmission line and related facilities, collectively referred to as the I-5 Corridor Reinforcement Project, in western portions of Washington State and Oregon. BPA expects that a decision whether to proceed with construction could be made in the first half of fiscal year 2017. If BPA decides to not proceed with this project, BPA will then evaluate the appropriate accounting treatment for applicable amounts recorded as construction work in progress.

3. Investments in U.S. Treasury Securities

<i>As of Sept. 30 — millions of dollars</i>	2016		2015	
	Amortized cost	Fair value	Amortized cost	Fair value
Short-term	\$ 272.9	\$ 272.9	\$ 694.3	\$ 694.6

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 market-based special securities. Under its banking arrangement with the U.S. Treasury, BPA had agreed to increase the amounts in the Bonneville Fund that are invested in market-based specials by at least \$100.0 million annually. However, as of Sept. 30, 2016, and after making its scheduled payment to the U.S. Treasury for bonds and other purposes, BPA is considered to be fully invested in market-based specials. As such, all balances in the Bonneville Fund will thereafter be invested through the Federal Investment Program and BPA will no longer earn interest offset credits. Instead, BPA will continue to earn interest on its investments in market-based specials. (See Note 1, Summary of Significant Accounting Policies.)

Market-based specials held during fiscal years 2016 and 2015 had a weighted-average yield of 0.6 percent and 0.1 percent, respectively, with maturities of up to two years. 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 in the Combined Balance Sheets as part of Cash and cash equivalents. For all other securities, FCRPS follows the authoritative guidance for investments, debt and equity securities. These investments are classified as held-to-maturity and reported at amortized cost. They are not actively traded and their valuations 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. These fair value measurements 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.) Investments with maturities that will be realized in cash between 91 days and one year are classified as short-term investments.

4. Effects of Regulation

REGULATORY ASSETS

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
IOU exchange benefits	\$ 2,551.9	\$ 2,683.9
Terminated nuclear facilities	1,879.6	2,030.9
Columbia River Fish Mitigation	711.0	695.8
Conservation measures	333.9	379.9
Fish and wildlife measures	282.6	298.9
REP Refund Amounts	222.8	294.2
Legal claims and settlements	54.0	55.6
Spacer damper replacement program	47.6	48.3
Federal Employees' Compensation Act	27.5	32.5
Trojan decommissioning and site restoration	26.7	25.6
Derivative instruments	21.2	33.7
Terminated hydro facilities	13.1	14.5
Other	8.3	9.4
Total	\$ 6,180.2	\$ 6,603.2

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 amortize 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.

"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.

"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.

"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.

"Legal claims and settlements" reflect amounts to be recovered in future rates to satisfy accrued liabilities related to outstanding legal claims and settlement agreements. These costs will be recovered and amortized to operations and maintenance expense over a period established by BPA.

"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.

“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.)

“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.)

“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.)

“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. These assets are amortized to nonfederal projects expense over the term of the related outstanding debt. (See Note 7, Debt and Appropriations.)

REGULATORY LIABILITIES

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
Capitalization adjustment	\$ 1,277.3	\$ 1,342.2
Accumulated plant removal costs	432.3	423.2
REP Refund Amounts to COUs	222.8	294.2
Decommissioning and site restoration	157.7	125.8
Derivative instruments	47.3	68.1
Other	6.4	6.3
Total	\$ 2,143.8	\$ 2,259.8

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 for fiscal years 2016, 2015 and 2014, respectively.

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

“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.)

“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.)

“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

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
Beginning Balance	\$ 184.8	\$ 176.1
Activities:		
Accretion	9.4	9.1
Expenditures	(2.7)	(2.1)
Revisions	(5.8)	1.7
Ending Balance	\$ 185.7	\$ 184.8

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.

AROs include the following items as of Sept. 30, 2016:

CGS decommissioning and site restoration of \$149.9 million

Trojan decommissioning of \$26.7 million

Energy Northwest Projects 1 and 4 site restoration of \$9.1 million

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

<i>As of Sept. 30 — millions of dollars</i>	2016		2015	
	Amortized cost	Fair value	Amortized cost	Fair value
Equity index funds	\$ 152.6	\$ 174.6	\$ 130.7	\$ 135.5
Bond index funds	118.6	120.5	130.3	129.6
U.S. government obligation mutual funds	19.5	19.2	19.0	17.6
Total	\$ 290.7	\$ 314.3	\$ 280.0	\$ 282.7

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 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.)

NOTES TO FINANCIAL STATEMENTS

Contribution payments to the CGS trust fund accounts for fiscal years 2016, 2015 and 2014 were \$3.5 million, \$3.4 million and \$3.2 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

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
Lease-Purchase trust funds	\$ 197.7	\$ 335.6
Derivative instruments	47.3	68.1
Settlements receivable	16.0	16.0
Funding agreements	14.4	11.7
Spectrum Relocation Fund	13.3	13.4
Other	5.1	5.1
Total	\$ 293.8	\$ 449.9

Deferred Charges and Other include the following items:

“Lease-Purchase trust funds” are amounts held in separate trust accounts outside the Bonneville Fund for the construction of leased transmission assets, the use of which BPA has received 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.) These trust balances consist of cash and cash equivalents and investments classified as either trading or held to maturity. Trading securities, which comprise the majority of trust balances, are held for construction purposes and are stated at fair value based on quoted market prices. 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.

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

“Settlements receivable” represents interest earned by BPA on certain settlements, the principal of which has been collected. The timing of cash receipt of the interest is unknown.

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

“Spectrum Relocation Fund” was created to reimburse certain federal agencies such as BPA for the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to the affected federal agencies. Amounts received for Spectrum Relocation Fund 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

		2016		2015	
	Terms	Carrying Value	Weighted-Average Interest Rate	Carrying Value	Weighted-Average Interest Rate
Nonfederal debt					
Nonfederal generation:					
Columbia Generating Station	0.7 – 6.8% through 2044	\$ 3,636.0	3.9%	\$ 3,453.0	4.0%
Cowlitz Falls Project	4.0 – 5.3% through 2032	78.9	5.1	82.1	5.1
Terminated nonfederal generation:					
Nuclear Project 1	0.7 – 5.0% through 2028	864.8	4.8	902.8	4.7
Nuclear Project 3	0.7 – 5.3% through 2028	1,068.1	4.8	1,132.7	4.7
Northern Wasco Hydro Project	1.5 – 5.0% through 2024	14.2	3.7	15.6	3.5
Lease-Purchase Program:					
Capital lease obligations	1.5 – 6.1% through 2042	1,707.7	2.7	1,181.0	2.9
Consolidated NIFC debt	1.8 – 5.4% through 2034	319.6	3.3	437.6	3.1
Other capital lease obligations	4.2 – 7.4% through 2043	41.3	5.4	32.1	6.4
Customer prepaid power purchases	4.3 – 4.6% through 2028	285.2	4.5	302.5	4.5
Total Nonfederal debt		\$ 8,015.8	3.9	\$ 7,539.4	4.0
Federal debt and appropriations					
Borrowings from U.S Treasury	0.5 – 5.9% through 2045	\$ 4,758.7	3.1	\$ 4,648.7	3.0
Federal appropriations	2.9 – 7.3% through 2066	2,430.2	5.1	3,513.8	5.8
Federal appropriations (not yet scheduled for repayment)		436.7	n/a	387.9	n/a
Total Federal debt and appropriations		\$ 7,625.6	3.8	\$ 8,550.4	4.2
Total debt and appropriations		\$ 15,641.4	3.8%	\$ 16,089.8	4.1%

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 all of Lewis County PUD's Cowlitz Falls Hydroelectric Project through 2032. 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 total project cash funding requirements, which include debt service and operating and maintenance expense. BPA recognized operating and maintenance expense for these projects of \$263.2 million, \$323.3 million and \$301.1 million in fiscal years 2016, 2015 and 2014, respectively, which is included in Operations and maintenance in the Combined Statements of Revenues and Expenses. Debt service expense for all projects of \$249.2 million, \$229.0 million and \$355.8 million for fiscal years 2016, 2015 and 2014, 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 2016 and 2015 were not used to fund the Energy Northwest-related principal payments as originally intended, and as included in rates. Instead, these principal amounts were refinanced to fiscal year 2032 at the latest. Amounts otherwise collected to fund these principal payments were used to prepay instead, before their maturity date, \$618.0 million and \$229.3 million of comparatively higher interest rate federal appropriations during fiscal years 2016 and 2015, respectively.

Also during fiscal year 2016, Energy Northwest funded operations and maintenance for Columbia Generating Station and interest expense on bonds previously issued for CGS and terminated nuclear Projects 1 and 3 with \$259.0 million received from a borrowing arrangement with a bank. This arrangement bears interest at variable rates and is due to be repaid on or before June 30, 2017. The rate was less than one percent per annum in fiscal year 2016. At the end of fiscal year 2016, BPA used the \$259.0 million, that it would otherwise have provided to Energy Northwest, to fund the prepayment of \$259.0 million of comparatively higher interest rate federal appropriations. These appropriations were otherwise anticipated to be prepaid at the end of fiscal year 2017. By June 30, 2017, BPA expects to fund Energy Northwest's repayment of the \$259.0 million it received under the borrowing agreement.

Amounts recorded in the FCRPS Combined Statements of Revenues and Expenses were not affected by the foregoing Energy Northwest borrowing arrangement. However, because the transaction deferred BPA's funding of Energy Northwest costs in the amount that Energy Northwest borrowed under the arrangement, the FCRPS Combined Statements of Cash Flows recorded a \$259.0 million increase to cash provided by operating activities. If the \$259.0 million is repaid as expected in fiscal year 2017, the FCRPS Combined Statements of Cash Flows will record a financing activity outflow.

Energy Northwest debt of \$1.64 billion is callable, in whole or in part, at Energy Northwest's option, on call dates between July 2017 and July 2026 at 100 percent of the principal amount.

The fair value of Energy Northwest debt exceeded carrying value by \$704.2 million and \$560.7 million as of Sept. 30, 2016, and 2015, respectively. The valuations are 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. These fair value measurements are considered Level 2 in the fair value hierarchy. (See Note 12, Fair Value Measurements.)

Lease-Purchase Program and Other capital lease obligations

Under the Lease-Purchase Program, BPA consolidates special purpose corporations, collectively referred to as Northwest Infrastructure Financing Corporations (NIFCs). These entities issued debt to and received advances from nonfederal sources, which were used to finance construction of transmission facilities leased to BPA. The combined NIFCs have issued \$119.6 million in bonds and borrowed \$200.0 million on a line of credit as of Sept. 30, 2016. The rental payments from BPA are pledged to the payment of the debt, but the facilities themselves do not secure the debt. The bonds bear interest at 5.4 percent and mature in 2034. All NIFC bonds outstanding are subject to redemption by the issuing 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. The line of credit becomes due in full on Jan. 1, 2019. 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.)

The fair value of the consolidated NIFC debt exceeded the carrying value by \$39.5 million and \$20.8 million as of Sept. 30, 2016, and 2015, respectively. The valuations are based on the discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2016, and 2015, respectively. These fair

value measurements are considered Level 2 in the fair value hierarchy. (See Note 12, Fair Value Measurements.)

Lease-purchase transactions with entities that are not consolidated in the FCRPS financial statements are reported as transmission capital leased assets. These include BPA's lease-purchase transactions 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.

On the Combined Balance Sheets, the consolidated NIFC debt and capital lease liabilities are included in Nonfederal debt. The related assets are included in Utility plant and 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.

In fiscal years 2016 and 2015, certain of the NIFC entities sold their lease receivables, rights to future lease revenues, and title to their leased assets to the Port of Morrow, resulting in the associated liabilities being reported as capital lease obligations instead of as consolidated NIFC debt. One of these transactions occurred in fiscal year 2016 and two occurred in fiscal year 2015. These transactions resulted in increases of \$124.9 million and \$303.3 million to transmission capital leased assets in fiscal years 2016 and 2015, respectively, with an immaterial net change in both years to Completed plant on the Combined Balance Sheets. (See Note 2, Utility Plant.)

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 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 Corps 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, 2016, of the total \$4.76 billion outstanding balance, none related to Northwest Power Act expenses. Outstanding bonds carrying a variable rate of interest were \$800.0 million and \$700.0 million at Sept. 30, 2016, and 2015, respectively. The weighted-average interest rate of BPA's borrowings from the U.S. Treasury exceeds current rates. As a result, the fair value of BPA's U.S. Treasury borrowings exceeded the carrying value by approximately \$651.2 million and \$474.5 million, based on discounted future cash flows using agency rates offered by the U.S. Treasury as of Sept. 30, 2016, and 2015, respectively, for similar maturities. These fair value measurements are considered Level 2 in the fair value hierarchy. (See discussion in Note 12, Fair Value Measurements.)

NOTES TO FINANCIAL STATEMENTS

Of the outstanding U.S. Treasury borrowings, \$218.8 million is not subject to redemption prior to their stated maturities. As of Sept. 30, 2016, \$800.0 million of borrowings are callable by BPA at par value and the remaining \$3.74 billion of borrowings 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 borrowings are called.

In fiscal years 2016 and 2015, BPA did not call any bonds it had issued to the U.S. Treasury. However, during fiscal year 2014, BPA called \$1.18 billion principal amount of previously issued U.S. Treasury borrowings prior to maturity and reissued \$1.14 billion principal amount of shorter-duration debt at lower interest rates. The result of these noncash transactions was a gain in fiscal year 2014 of \$36.0 million for extinguished debt, which decreased interest expense immediately, as well as a gain of \$3.0 million for modified debt, which is amortized to interest expense over the term of the new debt.

Federal appropriations

Federal appropriations reflect the responsibility that BPA has to repay congressionally appropriated amounts in the FCRPS. Federal appropriations consist primarily of the remaining unpaid power portion of Corps and Reclamation capital investments funded through congressional appropriations and include appropriations for Columbia River Fish Mitigation as allocated to the power purpose of the Corps' FCRPS hydroelectric projects.

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 reasonable expected service life of the facilities, not to exceed 50 years. Federal appropriations may be paid early without penalty, and BPA repaid appropriations early in fiscal years 2016 and 2015. All outstanding federal appropriations are scheduled for repayment in fiscal year 2020 and thereafter. 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.

			Maturing Nonfederal debt excluding capital leases		Future minimum lease payments under capital leases		Borrowings from U.S. Treasury		Federal appropriations		Total
As of Sept. 30 — millions of dollars											
2017	\$	855.8	\$	51.3	\$	76.1	\$	-	\$		983.2
2018		932.0		51.3		14.0		-			997.3
2019		644.8		61.6		574.9		-			1,281.3
2020		383.1		427.2		389.0		8.2			1,207.5
2021		386.7		615.4		275.0		63.2			1,340.3
2022 and thereafter		3,064.4		1,030.9		3,429.7		2,795.5			10,320.5
Total	\$	6,266.8	\$	2,237.7	\$	4,758.7	\$	2,866.9	\$		16,130.1
Less: Executory costs		-		27.9		-		-			27.9
Less: Amount representing interest		-		460.8		-		-			460.8
Present value of debt		6,266.8		1,749.0		4,758.7		2,866.9			15,641.4
Less: Current portion		855.8		1.8		76.1		-			933.7
Long-term debt	\$	5,411.0	\$	1,747.2	\$	4,682.6	\$	2,866.9	\$		14,707.7

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, such as the NIFCs. BPA is the primary beneficiary of the NIFCs, and BPA therefore consolidates the NIFCs into the FCRPS financial statements as VIEs. The key factors in this determination are BPA's ability to take contractual actions that significantly impact the economic, commercial and operating activities of the NIFCs and that BPA may be obligated to absorb losses that could be significant to the NIFCs. Additionally, BPA's lease-purchase agreements with the NIFC entities 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 the NIFC entities for all construction and operating risks associated with their respective transmission facilities.

Amounts related to the NIFC entities include Lease-Purchase trust funds and other assets of \$21.8 million and \$22.4 million and Nonfederal debt of \$319.6 million and \$437.6 million as of Sept. 30, 2016, and 2015, respectively. BPA has also entered into lease-purchase agreements with other 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 and, 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 \$21.6 million, \$19.7 million and \$21.8 million in fiscal years 2016, 2015 and 2014, 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

BACKGROUND

As provided in the Northwest Power Act, in 1981 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. In fiscal year 2012, 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 IOU's 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 2028, with remaining Scheduled Amounts as of Sept. 30, 2016, totaling

NOTES TO FINANCIAL STATEMENTS

\$3.09 billion. Amounts recorded of \$2.55 billion at Sept. 30, 2016, represent the present value of future cash outflows for these IOUs exchange benefits.

REP SCHEDULED AMOUNTS

As of Sept. 30 — millions of dollars

2017	\$	214.1
2018		232.2
2019		232.2
2020		245.2
2021		245.2
2022 through 2028		1,923.5
Subtotal of annual payments		3,092.4
Less: Discount for present value		540.5
IOU exchange benefits	\$	2,551.9

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, 2016, totaling \$229.6 million. Amounts recorded as a regulatory liability of \$222.8 million at Sept. 30, 2016, represent the present value of future cash flows for the amounts to be refunded to COUs.

10. Deferred Credits and Other

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
Customer reimbursable projects	\$ 196.8	\$ 216.5
Generation interconnection agreements	142.2	169.0
Third AC Intertie capacity agreements	97.7	99.9
Legal claims and settlements	34.4	33.7
Federal Employees' Compensation Act	27.5	32.5
Derivative instruments	21.2	33.7
Fiber optic leasing fees	18.0	21.9
Other	7.3	7.6
Total	\$ 545.1	\$ 614.8

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.

“Generation interconnection agreements” are generators’ advances held as security for requested new network upgrades and interconnection. 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 49-year life of the related assets.

“Legal claims and settlements” reflect amounts accrued for outstanding legal claims and settlements. (See Note 13, Commitments and Contingencies.)

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

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

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

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, cash in the form of prepayment or deposit of 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 2016, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2016, BPA had \$78.2 million in credit exposure related to purchase and sale contracts after taking into account netting rights. Of this credit exposure, \$50.1 million was related to sub-investment grade counterparties who provided letters of credit for \$36.4 million. 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 or related instruments to the U.S. Treasury. BPA manages the interest rate risk presented by variable rate U.S. Treasury debt by holding a like amount of variable rate U.S. Treasury security investments with a similar maturity profile. These U.S. Treasury investments earn interest at a variable rate that is correlated, but not identical, to the interest rate paid on U.S. Treasury variable rate debt. Energy Northwest may also issue variable rate debt for which BPA is expected to fund the repayment. (See Note 3, Investments in U.S. Treasury Securities and Note 7, Debt and Appropriations.)

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. These transactions 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 not eligible for the normal purchases and normal sales exception, BPA records unrealized gains and losses in Regulatory assets and Regulatory liabilities in 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, 2016, the derivative commodity contracts recorded at fair value totaled 4.7 million megawatt hours (MWh), gross basis, with delivery months extending to September 2022.

In 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 result in an asset of \$47.3 million and \$68.1 million and a liability of \$21.2 million and \$33.7 million as of Sept. 30, 2016, and 2015, respectively.

12. Fair Value Measurements

BPA applies fair value measurements and disclosures accounting guidance to certain assets and liabilities including commodity derivative instruments, nuclear decommissioning trusts and other investments. 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 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, 2016, and 2015. There were no transfers between Level 1 or Level 2 during the fiscal years ended Sept. 30, 2016, and 2015.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS*As of Sept. 30, 2016 — millions of dollars*

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity index funds	\$ 174.6	\$ —	\$ —	\$ 174.6
Bond index funds	120.5	—	—	120.5
U.S. government obligation mutual funds	19.2	—	—	19.2
Derivative instruments ¹				
Commodity contracts	—	47.3	—	47.3
Lease-Purchase trust funds				
U.S. government sponsored enterprise obligations	—	22.8	—	22.8
U.S. government obligations	—	120.9	—	120.9
Corporate obligations	—	13.0	—	13.0
Municipal obligations	—	13.2	—	13.2
Total	\$ 314.3	\$ 217.2	\$ —	\$ 531.5
Liabilities				
Derivative instruments ¹				
Commodity contracts	\$ —	\$ (21.2)	\$ —	\$ (21.2)
Total	\$ —	\$ (21.2)	\$ —	\$ (21.2)

As of Sept. 30, 2015 — millions of dollars

Assets				
Nonfederal nuclear decommissioning trusts				
Equity index funds	\$ 135.5	\$ —	\$ —	\$ 135.5
U.S. government obligation mutual funds	129.6	—	—	129.6
Corporate bond index funds	17.6	—	—	17.6
Derivative instruments ¹				
Commodity contracts	—	—	70.4	70.4
Lease-Purchase trust funds				
U.S. government sponsored enterprise obligations	—	199.0	—	199.0
U.S. government obligations	—	48.2	—	48.2
Corporate obligations	—	35.7	—	35.7
Municipal obligations	—	22.4	—	22.4
Total	\$ 282.7	\$ 305.3	\$ 70.4	\$ 658.4
Liabilities				
Derivative instruments ¹				
Commodity contracts	\$ —	\$ (33.7)	\$ —	\$ (33.7)
Total	\$ —	\$ (33.7)	\$ —	\$ (33.7)

¹ Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other in the Combined Balance Sheets, respectively. (See Note 6, Deferred Charges and Other and Note 10, Deferred Credits and Other.) 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 long-dated power contracts measured at fair value on a recurring basis using the California-Oregon Border (COB) and Mid-Columbia (Mid-C) 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 a significantly higher or lower fair value measurement.

Forward power prices are influenced by, among other factors, the price of natural gas, seasonality, hydro forecasts, expectations of demand growth, planned changes in the regional generating plants, and the emergence of new marginal fuels for generation.

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.

<i>As of Sept. 30 — millions of dollars</i>	2016	2015
Beginning Balance	\$ 70.4	\$ 4.7
Changes in unrealized gains (losses) ¹	(23.2)	65.7
Transfers out of Level 3 to Level 2	(47.2)	-
Ending Balance	\$ -	\$ 70.4

¹ Unrealized gains and losses are included in Regulatory assets and Regulatory liabilities in the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power, respectively, in the Combined Statements of Revenues and Expenses.

During fiscal year 2016, transfers out of Level 3 occurred when the significant inputs became more observable, such as when the time between the valuation date and the delivery term of a transaction became shorter.

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 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, 2016, BPA has entered into long-term fish and wildlife agreements with estimated contractual commitments of \$468.1 million. These agreements will expire at various dates between fiscal years 2018 and 2025.

IRRIGATION ASSISTANCE**Scheduled distributions***As of Sept. 30 — millions of dollars*

2017	\$	50.8
2018		27.2
2019		56.6
2020		24.3
2021		14.8
2022 through 2045		268.4
Total	\$	442.1

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 \$442.1 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*

2017	\$	70.5
2018		74.8
2019		77.6
2020		43.9
2021		33.6
Total	\$	300.4

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 six purchases made specifically to meet BPA's commitments to sell power at Tier 2 rates in fiscal years 2017-2019 and two purchases to meet load obligations in Idaho. The expenses associated with Tier 2 purchases to meet prior commitments were \$22.1 million, \$24.6 million and \$4.9 million for fiscal years 2016, 2015 and 2014, respectively. The expenses associated with the Idaho purchases, which are not included in the Tier 2 amounts, commenced July 1, 2016, and were \$9.0 million for fiscal 2016. 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 \$78.0 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 2020.

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 \$19.6 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is \$7.3 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is \$5.3 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 \$375.0 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, 2016, there have been no assessments to BPA under either of these programs.

ENVIRONMENTAL MATTERS

From time to time there are sites for which BPA, the Corps 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, the Corps 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, 2016, 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 pending 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. BPA has recorded a liability of \$34.4 million, including interest, on the basis that all conditions have been met except the final resolution in the California refund proceedings and related litigation, which management considers probable. BPA established an offsetting regulatory asset, as the costs will be collected in future rates.

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.

In May 2012, the Court of Federal Claims issued an opinion that held that BPA breached its contracts with the California parties. Assuming the amounts owed included interest, such refunds could have amounted up to \$51.8 million. While the ruling did not establish a specific liability in this matter, BPA recorded a liability in this amount in fiscal year 2012.

On April 2, 2013, the Court of Federal Claims issued a Declaratory Judgment in favor of the California parties in response to motions by these parties requesting declaratory relief for certain transactions.

Thereafter, a new judge for the Court of Federal Claims was assigned to the claims, and on Dec. 20, 2013, she vacated the May 2012 opinion. After hearings conducted in June 2014 and January 2015, at the judge's request, BPA filed a motion to dismiss the claims. On March 12, 2015, the judge issued a decision granting BPA's motion to dismiss and holding that the California parties lacked standing to sue because they had no contractual privity with BPA. The judge also found that even if the California parties had standing, the breach of contract claims should nevertheless be dismissed because the factual predicate for a breach of contract claim against Bonneville did not exist because FERC had not retroactively revised the rates applicable to the BPA transactions, as alleged by the California parties. Thereafter the California parties filed appeals of the order in the United States Court of Appeals for the Federal Circuit. On Oct. 3, 2016, the Federal Circuit Court of

Appeals affirmed the dismissal by the Court of Federal Claims of all breach of contract claims against Bonneville.

In a separate proceeding as part of FERC's California refund docket, an administrative law judge appointed by the FERC Commissioners conducted a hearing in 2012 to make certain findings related to certain classes of transactions at issue in the California parties' breach of contract litigation in the Court of Federal Claims. The FERC proceeding had potential impacts on the scope of potential damages in the breach of contract case. On Feb. 15, 2013, the FERC administrative law judge issued findings to the effect that the prices involved in certain transactions were unjust and unreasonable and subject to refund and recommended that BPA pay \$59.6 million, plus interest. On Nov. 10, 2014, FERC dismissed BPA from the FERC California refund proceeding and did not affirm the administrative law judge's findings and recommendations. The California parties did not appeal the dismissal of BPA from the proceeding.

In fiscal year 2015, BPA removed its liability for the California parties' refund claims as a result of the judge's dismissal in 2015 of all the claims in the Court of Federal Claims on the basis that BPA's management has determined that the probability of financial loss is remote.

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 2016.

Judgments and settlements are included in FCRPS costs and recovered through rates. Except with respect to the SCE matter described above, no liability has been recorded for the above legal matters. (See Note 10, Deferred Credits and Other, for discussion of amounts accrued for outstanding legal claims and settlements.)

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APPENDIX B-2

**FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR
THE NINE MONTHS ENDED JUNE 30, 2017**

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Federal Columbia River Power System

Combined Balance Sheets ^(Unaudited)

(Millions of dollars)

	As of June 30, <u>2017</u>	As of September 30, <u>2016</u>
Assets		
Utility plant		
Completed plant	\$ 18,605.9	\$ 18,276.5
Accumulated depreciation	(6,527.3)	(6,310.4)
Net completed plant	12,078.6	11,966.1
Construction work in progress	1,246.4	1,312.0
Net utility plant	13,325.0	13,278.1
Nonfederal generation	3,565.0	3,504.8
Current assets		
Cash and cash equivalents	434.8	579.6
Short-term investments in U.S. Treasury securities	829.9	272.9
Accounts receivable, net of allowance	46.4	50.5
Accrued unbilled revenues	301.0	279.8
Materials and supplies, at average cost	116.3	111.9
Prepaid expenses	41.6	31.8
Total current assets	1,770.0	1,326.5
Other assets		
Regulatory assets	5,991.4	6,180.2
Nonfederal nuclear decommissioning trusts	335.2	314.3
Deferred charges and other	309.6	293.8
Total other assets	6,636.2	6,788.3
Total assets	\$ 25,296.2	\$ 24,897.7
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	\$ 3,751.8	\$ 3,392.6
Debt		
Federal appropriations	2,915.1	2,866.9
Borrowings from U.S. Treasury	4,673.6	4,682.6
Nonfederal debt	6,879.4	7,158.2
Total capitalization and long-term liabilities	18,219.9	18,100.3
Commitments and contingencies (See Note 13 to 2016 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	85.1	76.1
Nonfederal debt	1,335.5	857.6
Accounts payable and other	443.6	437.2
Total current liabilities	1,864.2	1,370.9
Other liabilities		
Regulatory liabilities	2,066.5	2,143.8
IOU exchange benefits	2,444.7	2,551.9
Asset retirement obligations	189.9	185.7
Deferred credits and other	511.0	545.1
Total other liabilities	5,212.1	5,426.5
Total capitalization and liabilities	\$ 25,296.2	\$ 24,897.7

Federal Columbia River Power System

Combined Statements of Revenues and Expenses ^(Unaudited)

(Millions of dollars)

	Three Months Ended June 30,		Fiscal Year-to-Date Ended June 30,	
	<u>2017</u>	<u>2016</u>	<u>2017</u>	<u>2016</u>
Operating revenues				
Sales	\$ 817.5	\$ 779.1	\$ 2,622.4	\$ 2,498.0
U.S. Treasury credits	16.5	16.0	50.6	63.8
Miscellaneous revenues	19.0	21.0	54.6	61.5
Total operating revenues	853.0	816.1	2,727.6	2,623.3
Operating expenses				
Operations and maintenance	533.3	498.8	1,572.8	1,461.3
Purchased power	21.0	16.3	80.1	83.8
Nonfederal projects	51.6	63.9	167.5	193.0
Depreciation and amortization	122.0	120.6	364.1	350.8
Total operating expenses	727.9	699.6	2,184.5	2,088.9
Net operating revenues	125.1	116.5	543.1	534.4
Interest expense and (income)				
Interest expense	71.2	87.7	212.6	261.7
Allowance for funds used during construction	(8.0)	(7.6)	(25.2)	(31.3)
Interest income	(1.7)	(4.5)	(3.5)	(7.7)
Net interest expense	61.5	75.6	183.9	222.7
Net revenues	\$ 63.6	\$ 40.9	\$ 359.2	\$ 311.7

APPENDIX C

FORM OF OPINION OF CHAPMAN AND CUTLER LLP

(Date of Closing)

Idaho Energy Resources Authority
802 West Bannock Street, Suite 900
Boise, Idaho 83702

Re: \$200,765,000
Idaho Energy Resources Authority
Transmission Facilities Revenue Bonds
(Bonneville Cooperation Project No. 1),
Series 2017 (Federally Taxable)

The Idaho Energy Resources Authority (the “*Issuer*”) has on this date issued its Transmission Facilities Revenue Bonds, (Bonneville Cooperation Project No. 1), Series 2017 (Federally Taxable), in the aggregate principal amount of \$200,765,000 (the “*Series 2017 Bonds*”), dated as of the date hereof, maturing on September 1 of each of the years and bearing interest as follows:

SEPTEMBER 1 OF THE YEAR	AMOUNT MATURING	INTEREST RATE
2023	\$25,765,000	2.297%
2024	30,000,000	2.447
2026	70,000,000	2.772
2028	75,000,000	2.952

The Series 2017 Bonds are authorized to be issued pursuant to an Indenture of Trust dated as of September 1, 2017 (the “*Indenture*”), between the Issuer and U.S. Bank National Association, as trustee (the “*Trustee*”). This opinion is delivered pursuant to the requirements of Section 2.04 of the Indenture. Capitalized terms used and not otherwise defined herein have the meanings assigned to them in the Indenture.

The Series 2017 Bonds are issued under the authority contained in the Idaho Energy Resources Authority Act, Title 67, Chapter 89, Idaho Code, as amended (the “*Act*”) for the purpose of providing funds sufficient to refinance indebtedness issued to finance the cost of acquiring, constructing, improving and equipping certain transmission facilities to be owned by the Issuer and leased to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration (“*Bonneville*”), pursuant to a Lease-Purchase Agreement, dated September 21, 2017 (the “*Lease-Purchase Agreement*”), between the Issuer and Bonneville. All right, title and interest of the Issuer in and to the Lease-Purchase Agreement, including all lease rentals, revenues and receipts payable or receivable thereunder, excluding, however, the Issuer’s Reserved Rights, has been pledged as part of the Trust Estate pursuant to the Indenture for the payment of principal of and interest on the Series 2017 Bonds.

The Series 2017 Bonds are special and limited obligations of the Issuer, payable solely from the Trust Estate pledged under the Indenture for the payment of the principal and Redemption Price of and interest on the Series 2017 Bonds. The Series 2017 Bonds do not and shall not constitute or become an indebtedness or a debt or

liability of the State of Idaho (the “State”) or any agency or subdivision thereof, and neither the State nor any of its agencies or subdivisions are or shall be liable on the Series 2017 Bonds nor shall the Series 2017 Bonds constitute the giving, pledging or loaning of the faith and credit of the State or any agency or subdivision thereof. The issuance of Series 2017 Bonds does not and shall not, directly, indirectly or contingently, obligate the State or any agency or subdivision thereof to levy or collect any form of taxes or assessments for their payment or to create any indebtedness payable out of taxes or assessments.

Reference is made to the Indenture for a description of the covenants and undertakings of the Issuer in connection with the Series 2017 Bonds and the pledge and assignment to the Trustee of the Trust Estate under the Indenture for the payment of the principal and redemption price of and interest on the Series 2017 Bonds.

In connection with the issuance of the Series 2017 Bonds, we have examined: (a) the Act; (b) Resolution No. 2017-3 adopted by the Board of Directors of the Issuer on July 20, 2017, authorizing the issuance of the Series 2017 Bonds, and approving the Indenture and the Lease-Purchase Agreement (the “Resolution”); (c) executed counterparts of the Indenture and the Lease-Purchase Agreement; (d) certifications of the Issuer and Bonneville, (e) the opinion of Williams Bradbury, P.C., counsel to the Issuer, dated the date hereof, and (f) such other materials, showings and documents as we deem necessary for the purpose of this opinion.

Based upon and subject to the foregoing, we are of the opinion that:

- (1) The Resolution has been duly adopted, executed and delivered by the Issuer.
- (2) The Series 2017 Bonds have been duly and validly issued by the Issuer in accordance with the Act and the Indenture and constitute the valid and binding special and limited obligations of the Issuer, payable solely from the Trust Estate.
- (3) The Indenture constitutes the valid and binding obligation of the Issuer, and is enforceable against the Issuer in accordance with its terms. The Indenture creates the valid pledge of the Trust Estate, subject to the provisions of the Indenture permitting application thereof for the purposes and on the terms and conditions set forth in the Indenture.
- (4) The Lease-Purchase Agreement constitutes the valid and binding agreement of the Issuer, and is enforceable against the Issuer in accordance with its terms.
- (5) Interest on the Series 2017 Bonds is includible in gross income of the owners thereof for federal income tax purposes.
- (6) Under the laws of the State as presently enacted and construed, interest on the Series 2017 Bonds is not subject to the income tax or the franchise tax imposed by the State under the Idaho Income Tax Act; *provided, however*, that Bond Counsel expresses no opinion concerning whether the interest on the Series 2017 Bonds held by an S corporation or an electing small business trust is subject to the income tax or the franchise tax imposed by the State. Bond counsel expresses no opinion with respect to taxation under any other provisions of Idaho law.

We observe that ownership or disposition of the Series 2017 Bonds may result in other federal, state and local income tax consequences to certain taxpayers, and we express no opinion regarding any such collateral consequences arising with respect to the Series 2017 Bonds. Bondholders should consult their own tax advisors concerning tax consequences of ownership of the Series 2017 Bonds.

Enforceability of the Series 2017 Bonds, the Indenture and the Lease-Purchase Agreement may be limited by bankruptcy, insolvency, reorganization and other similar laws relating to the enforcement of creditors’ rights generally or usual equity principles in the event equitable remedies are sought.

We express no opinion as to the accuracy, adequacy or completeness of the Official Statement relating to the Series 2017 Bonds.

In rendering this opinion, we have relied upon certifications of the Issuer with respect to certain material facts within the Issuer's knowledge. Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render our opinion, and is not a guarantee of a result.

This opinion is given as of the date hereof and we assume no obligation to 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.

Respectfully submitted,

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APPENDIX D

FORM OF CONTINUING DISCLOSURE CERTIFICATE

CONTINUING DISCLOSURE CERTIFICATE

\$200,765,000

**IDAHO ENERGY RESOURCES AUTHORITY
TRANSMISSION FACILITIES REVENUE BONDS
(BONNEVILLE COOPERATION PROJECT NO. 1)
SERIES 2017**

This Continuing Disclosure Certificate (the “Certificate”) is executed and delivered by the Bonneville Power Administration (“Bonneville”) as the obligated person for whom financial and operating data is presented in the official statement for the Idaho Energy Resources Authority (the “Issuer”) Transmission Facilities Revenue Bonds (Bonneville Cooperation Project No. 1) Series 2017 (the “Bonds”).

Section 1. Purpose of Certificate. This Certificate is being executed and delivered by Bonneville for the benefit of the holders of the Bonds and to assist the underwriters of the Bonds in complying with paragraph (b)(5) of the United States Securities and Exchange Commission Rule 15c2-12 (17 C.F.R. § 240.15c2-12) as amended (the “Rule”). This Certificate constitutes Bonneville’s written undertaking for the benefit of the owners of the Bonds as required by paragraph (b)(5) of the Rule.

Section 2. Definitions. Unless the context otherwise requires, the terms defined in this Section shall, for purposes of this Certificate, have the meanings herein specified.

“Beneficial Owner” means any person who has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of any Bonds, including persons holding Bonds through nominees or depositories.

“BPA Annual Information” means financial information and operating data generally of the type included in Appendix A of the Official Statement under the heading “POWER SERVICES” in the tables titled “Bonneville Power Services’ Ten Largest Customers by Sales” and “Historical Average PF Preference Rates,” under the heading “TRANSMISSION SERVICES” in the table titled “Transmission Services’ Ten Largest Customers By Sales,” and under the heading “BONNEVILLE FINANCIAL OPERATIONS” in the tables titled “Historical Capital Spending by Program by Fiscal Year,” “Historical Capital Funding by Source and Fiscal Year,” “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.”

“Commission” means the United States Securities and Exchange Commission.

“FCRPS” means the Federal Columbia River Power System.

“FCRPS Fiscal Year” means the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year end is changed, Bonneville shall provide written notice of such change to the MSRB.

“MSRB” means the United States Municipal Securities Rulemaking Board or any successor to its functions.

“Official Statement” means the final official statement for the Bonds dated September 11, 2017.

“Rule” means the Commission’s Rule 15c2-12 under the Securities Exchange Act of 1934, as it has been and may be amended.

Section 3. Financial Information. Bonneville agrees to provide or cause to be provided to the MSRB, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2017:

- i. the BPA Annual Information for the FCRPS Fiscal Year; and
- ii. annual financial statements of the FCRPS for the FCRPS Fiscal Year, prepared in accordance with generally accepted accounting principles; and
- iii. if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville will notify the Issuer when the financial information in this section has been provided to the MSRB.

Bonneville agrees to notify the MSRB in a timely manner of any failure to provide the information described in Section 3 on or prior to the date set forth in the preceding paragraph.

Section 4. Events Notices. Bonneville agrees to provide to the MSRB and the Issuer in a timely manner not in excess of ten business days after the occurrence of the event, notice of any of the following events with respect to the Bonds:

1. principal and interest payment delinquencies;
2. non-payment related defaults, if material;
3. unscheduled draws on debt service reserves reflecting financial difficulties;
4. unscheduled draws on credit enhancements reflecting financial difficulties;
5. substitution of credit or liquidity providers or their failure to perform;
6. adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds;
7. modifications to the rights of Bondholders, if material;
8. bond calls, if material, and tender offers;
9. defeasances;
10. release, substitution or sale of property securing repayment of the Bonds, if material;
11. rating changes;
12. bankruptcy, insolvency, receivership or similar event of the obligated person (Note: For the purposes of the event identified in this paragraph 12, the event is considered to occur when any of the following occur: The appointment of a receiver, fiscal agent or similar officer for an obligated person in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the obligated person, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan

of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person);

13. the consummation of a merger, consolidation, or acquisition involving an obligated person or the sale of all or substantially all of the assets of the obligated person, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

14. appointment of a successor or additional trustee or the change of name of a trustee, if material.

Section 5. Termination. Bonneville's obligations to provide notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Bonds. In addition, Bonneville may terminate all or any portion of its obligations under this Certificate if Bonneville (a) obtains an opinion of nationally recognized bond counsel to the effect that those portions of the Rule which require this Certificate, or any provision of this Certificate, are invalid, have been repealed retroactively or otherwise do not apply to the Bonds; and (b) notifies the MSRB of such opinion and the termination of its obligations under this Certificate.

Section 6. Amendment. Notwithstanding any other provision of this Certificate, Bonneville may amend this Certificate, provided that the following conditions are satisfied:

A. If the amendment relates to the provisions of Sections 3 or 5 hereof, it may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature or status of Bonneville with respect to the Bonds, or the type of business conducted; and,

B. If this Certificate, as amended, would, in the opinion of nationally recognized bond counsel, have complied with the requirements of the Rule at the time of the original issuance of the Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

C. The amendment either (i) is approved by the owners of the Bonds pursuant to the terms of the governing instrument at the time of the amendment or (ii) does not materially impair the interests of the owners or Beneficial Owners of the Bonds as determined by a party unaffiliated with the obligated person.

In the event of any amendment of a provision of this Certificate, Bonneville shall describe such amendment in its next annual filing pursuant to Section 3 of this Certificate, and shall include, as applicable, a narrative explanation of the reason for the amendment and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by Bonneville. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of the amendment shall be given in the same manner as for a listed event under Section 4 hereof, and (ii) the annual report for the first fiscal year that is affected by the change in accounting principles should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Section 7. Bond Owner's Remedies Under This Certificate. The right of any owner of Bonds or Beneficial Owner of Bonds to obtain legal redress for Bonneville's failure to comply with provisions of this Certificate, or for any breach or default by Bonneville of this Certificate, shall not include monetary damages and any failure by Bonneville to comply with the provisions of this Certificate shall not be an event of default with respect to the Bonds. Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Certificate. Any owner of Bonds or Beneficial Owner of Bonds shall have only such other rights and remedies available to it under federal law with respect to Bonneville.

Section 8. Form of Information. All information required to be provided under this certificate will be provided in an electronic format as prescribed by the MSRB and with the identifying information prescribed by the MSRB.

Section 9. Submitting Information Through EMMA. So long as the MSRB continues to approve the use of the Electronic Municipal Market Access (“EMMA”) continuing disclosure service, any information required to be provided to the MSRB under this Certificate may be provided through EMMA. As of the date of this Certificate, the web portal for EMMA is emma.msrb.org.

Section 10. Choice of Law. This Certificate shall be governed by and construed in accordance with federal law, including federal securities laws and official interpretations thereof.

Dated as of the 21st day of September, 2017.

Bonneville Power Administration

Authorized Official

