NEW ISSUE **BOOK-ENTRY ONLY**

$119,585,000
NORTHWEST INFRASTRUCTURE FINANCING CORPORATION
Transmission Facilities Lease Revenue Bonds
Series 2004

Dated: Date of Delivery Due: January 1, 2034

The Series 2004 Bonds will be limited obligations of 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 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 Agreement will be made solely from the Bonneville Fund. The Lease Agreement provides that Bonneville's obligation to pay the rent and all amounts payable under the Lease 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 2004 Bonds has been complete or is operating or operable. Bonneville's payment obligations under the Lease 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 Series 2004 Bonds are being issued for the principal purpose of paying the cost of acquisition, construction and equipping of certain transmission facilities to be leased to Bonneville. See "THE PROJECT".

The Series 2004 Bonds will bear interest at 5.379% per annum, payable semi-annually on January 1 and July 1 of each year, commencing July 1, 2004.

The Series 2004 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 2004 Bonds. Individual purchases in principal amounts of $5,000 or multiples thereof will be made only through the book-entry system maintained by DTC through brokers and dealers who are, or act through, DTC Participants. The purchasers of the Series 2004 Bonds will not receive certificates representing their interest in the Series 2004 Bonds. Ownership interests in the Series 2004 Bonds will be shown on, and transfers of Series 2004 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 2004 Bonds will be made to owners by DTC through its participants.

The Trustee for the Series 2004 Bonds is U.S. Bank National Association.

The Series 2004 Bonds are subject to redemption prior to maturity as described herein.

Offering Price:
100%

The Series 2004 Bonds are offered when, as and if issued and received by the Underwriters, subject to the approval of the proceedings authorizing the Series 2004 Bonds by Orrick, Herrington & Sutcliffe LLP, and to certain other conditions. Certain legal matters will be passed upon for the Issuer by Ropes & Gray LLP 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 Fulbright & Jaworski L.L.P., New York, New York. The Series 2004 Bonds are expected to be delivered through the facilities of DTC on or about March 25, 2004.

Goldman, Sachs & Co.

Citigroup **JPMorgan**

March 10, 2004

The information contained in this Offering Memorandum has been obtained from Northwest Infrastructure Financing Corporation (the "Issuer") and the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") and other sources which are deemed to be reliable. This Offering Memorandum 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 Offering Memorandum 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 Goldman Sachs & Co. and the other Underwriters (collectively the "Underwriters") to give any information or to make any representations other than as contained in this Offering Memorandum 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 Offering Memorandum 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 Offering Memorandum. The Underwriters have reviewed the information in the Offering Memorandum 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 Offering Memorandum and takes no responsibility for its contents, other than the information relating to the Issuer under the headings "THE ISSUER" and "LEGAL MATTERS."

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS WHICH STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE MARKET PRICE OF THE SERIES 2004 BONDS.

This Offering Memorandum 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.

The prospective financial information included in this offering document, including any forward-looking or prospective financial information, has been prepared by, and is the responsibility of the management of Bonneville. PricewaterhouseCoopers has neither examined nor compiled such prospective financial information, and accordingly, PricewaterhouseCoopers does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers reports included in this offering document relate to the historical financial information of Bonneville. They do not extend to the prospective financial information and should not be read to do so.

TABLE OF CONTENTS

(THIS PAGE INTENTIONALLY LEFT BLANK)

OFFERING MEMORANDUM

$119,585,000
Northwest Infrastructure Financing Corporation
Transmission Facilities Lease Revenue Bonds
Series 2004

INTRODUCTORY STATEMENT

This Offering Memorandum provides information concerning the issuance by the Northwest Infrastructure Financing Corporation (the "Issuer") of $119,585,000 principal amount of its Transmission Facilities Lease Revenue Bonds, Series 2004 (the "Series 2004 Bonds"). The Series 2004 Bonds are being issued to finance the costs of acquiring, constructing and equipping certain transmission facilities (the "Project") located within the State of Washington (the "State") 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 Agreement with Bonneville dated as of March 1, 2004 (the "Lease Agreement") pursuant to which the Issuer will lease the Project to Bonneville. The Series 2004 Bonds will be issued under an Indenture of Trust dated as of March 1, 2004 (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 Agreement, including the right to receive lease payments from Bonneville in amounts at least sufficient to pay when due the principal of, and interest, on the Series 2004 Bonds. The Issuer and Bonneville will also enter into a Construction Agency Agreement dated as of March 1, 2004 (the "Construction Agency Agreement") pursuant to which Bonneville will act as agent of the Issuer in acquiring, constructing and equipping the Project.

Brief descriptions and summaries of the Series 2004 Bonds, the Lease Agreement and the Indenture follow in this Offering Memorandum. 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, Corporate Trust Services, 555 SW Oak Street, PD-OR-PTD, Portland, Oregon 97204. Appendices A and B to this Offering Memorandum 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

The Issuer is a special purpose Delaware corporation that has been recently organized solely for the purpose of acquiring and constructing the facilities comprising the Project, leasing those facilities to Bonneville, and financing the Project with the proceeds of the Series 2004 Bonds. The Issuer's capitalization is nominal and it has no source of income other than payments to it by Bonneville under the Lease Agreement. The Issuer's financial condition is not material to an investment in the Series 2004 Bonds, and accordingly the Issuer is not providing any disclosure regarding its financial condition.

All the shares of capital stock of the Issuer are held by The NIFC Trust, a Massachusetts charitable lead trust formed by J.H. Management Corporation and JH Holdings Corporation, both of which are Massachusetts corporations, for the benefit of a Massachusetts charitable institution. Recourse under the Indenture against the incorporator, directors, officers and stockholders of the Issuer and J.H. Management Corporation has been expressly waived by the Trustee, on behalf of all holders of the Series 2004 Bonds and, accordingly, none of such persons or entities will have any liability for any payments of principal or interest on the Series 2004 Bonds.

The Issuer's executive officers are located at Room 43/50, One International Place, Boston, Massachusetts 02110-2624, and its telephone number is (617) 951-7690.

The Series 2004 Bonds are limited recourse obligations of the Issuer and shall be payable by the Issuer solely from, and shall be secured solely by, the Trust Estate and nothing in the Series 2004 Bonds, in the Lease Agreement or in the Indenture shall be considered as pledging any other funds or assets of the Issuer.

THE PROJECT AND USE OF PROCEEDS

The Project will consist solely of fixtures, primarily transmission lines and towers, associated with a new 64 mile long 500-kV transmission line. The line will connect Bonneville's existing Schultz Substation near Ellensburg, Washington, to a new substation which will not be part of the Project. The new line will run through the middle of the Columbia River Basin, cross the Hanford Reach National Monument and cross the U.S. Army's Yakima Firing Range. The Project will also include all of the new transmission line and towers on 9 miles of replacement transmission facilities running from Bonneville's Midway Substation to its Vantage Substation which will convert an existing 230kV single circuit line to a double circuit line composed of the existing line and a new 500-kV line on new upgraded transmission towers. Under the Lease 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.

In January 2003 Bonneville completed the National Environmental Policy Act requirements associated with the Project and published a Record of Decision in March 2003 stating that Bonneville will be constructing the above described Project. All permits and licenses necessary for constructing the Project have been obtained.

Under the Construction Agency Agreement, Bonneville will construct the Project on behalf of the Issuer. Bonneville has completed the design for the entire Project and all its components. By the end of calendar year 2003, Bonneville received 90% of the materials for the construction of the transmission line and the two substation terminals. Bonneville awarded a contract for major Project construction work in January 2004, with construction scheduled to start spring 2004, be complete by winter 2005 and energized by spring 2006.

The Project is expected to add about 400-600 megawatts of transfer capacity to Bonneville's transmission grid in central Washington State. It is designed to relieve transmission congestion on a congested transmission path (the "North-of-Hanford Path") and along the heavily populated area surrounding the northern portions of Interstate 5 (the "I-5 Corridor) during spring and summer months when there are high north-to-south transmission flows from Canada and high hydroelectric generation on the upper Columbia River. Relieving congestion across the North-of-Hanford Path will allow another path, the North-of-John Day Path, to be used more fully because the two are in series. This, in turn, will maintain higher operational transfer capability on the North-South Intertie, thereby reducing curtailments of power flows between California and the Pacific Northwest. Bonneville has a number of agreements that require it to maintain the ratings of said Intertie. The Project will also assist Bonneville in providing firm transmission service to proposed new generators in the northern part of the I-5 Corridor. The new generation will add stability to the already taxed transmission system.

The proceeds from the sale of the Series 2004 Bonds will be applied to the cost of acquiring, constructing and equipping the Project. Costs of issuance of the Series 2004 Bonds (including Underwriters' discount) of approximately $1,531,109 will also be paid from proceeds of the Series 2004 Bonds.

SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2004 BONDS

Trust Estate

Under the terms of the Indenture, the Series 2004 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 Agreement, including all lease rentals, 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 Agreement; (iii) all moneys and securities from time to time held by the Trustee under the terms of the Indenture including amounts set apart and transferred to the Project Fund, the Bond Fund or any special fund, and all investment earnings of any of the foregoing, subject to disbursements from the Project Fund, the Bond Fund or any such special fund in accordance with the provisions of the Lease Agreement and the Indenture; (iv) any and all other property of every kind and nature from time to time which was heretofore or hereafter is 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 Agreement between Bonneville and the Issuer, Bonneville is required to make lease rental payments in the amounts set forth in a schedule set forth in the Lease Agreement which schedule will provide for lease payments at times and in amounts more than sufficient to pay the principal of and interest and all other amounts due on the Series 2004 Bonds. See herein “THE LEASE 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 2004 Bonds. The Lease Agreement provides that such lease rental payments will be made directly to the Trustee for deposit in the Bond Fund.

The Lease Agreement provides that Bonneville’s obligation to pay the rent and all other amounts payable under the Lease Agreement and to maintain the Project in accordance with the Lease Agreement is absolute and unconditional, and is payable without any set-off or counterclaim, regardless of whether or not the Project has been completed as provided in the Lease Agreement or is operating or operable. Bonneville’s obligation to make the lease rental payments will continue until January 1, 2034 unless sooner terminated or extended in accordance with the provisions of the Lease Agreement. **Bonneville’s obligations under the Lease 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 lease term, 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 term and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease Agreement. The Issuer and Bonneville will declare that the Lease 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 under the Washington Uniform Commercial Code or otherwise. The Trust Estate includes the pledge of all of the right, title and interest of the Issuer in and to the Project, subject to the Lease Agreement which as described above limits remedies with respect to the Project. Therefore, the Bondholders should not look to the Project as providing any security for the payment of Bonds.

Source of Bonneville’s Payments: The Bonneville Fund

Payments by Bonneville under the Lease Agreement are to be made from the Bonneville Fund, into which flow all of Bonneville’s receipts, collections and other recoveries of Bonneville in cash from all sources, subject to the limitations on the use of such Fund. Bonneville’s payment obligations under the Lease Agreement are not, nor shall they be construed to be, general obligations of the United States Government nor are such obligations intended to be or are they secured by the full faith and credit of the United States of America.

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.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal 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 Bureau of Reclamation for certain costs allocated to 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 2003 payment responsibility to the United States Treasury in full and on time.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville for operating and maintenance expenses, including payments under the Lease 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 dating to the Lease Agreement and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) to (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 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, pursuant to which Bonneville provides credits against power and transmission purchases made from Bonneville by such customers. Under these "net billing" agreements, related Bonneville Preference Customers ("Participants") make payments to two third parties (Energy Northwest and the City of Eugene, Oregon, Water and Electric Board) to meet the costs of several nuclear generating projects. In return, Bonneville provides to the Participants payment credits against the monthly power and transmission bills issued by Bonneville. Subject to certain limitations and exceptions, the net billing credits are provided in amounts equivalent to the payments the Participants make to the third parties. Once the Participants have satisfied their payment obligations to the third parties in a related net billing agreement contract year, and Bonneville has provided the Participants equivalent dollar amounts of credits in such year, the Participants resume paying their respective power and transmission bills directly to Bonneville. The cash payments to Bonneville continue until the next annual billing cycle begins under the respective net billing agreements, although it is possible that the third parties may reinitiate net billing in a contract year to cover unexpected costs.

The net billing arrangements have had and are expected to have the effect of reducing Bonneville's revenues in cash during early portions of Bonneville's fiscal year since Bonneville does not realize a substantial amount of payments in cash from its power and transmission sales to the Participants. As a group, Participants constitute Bonneville's largest customer base. The period in a fiscal year during which net billing is operative varies by Participant and project, but, in general depends on the amounts of and rates for power and transmission service purchased from Bonneville by Participants, and on the costs of the related projects.

For additional descriptions of Bonneville's substantial net billing arrangements, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—Power Business Line—Description of the Generation Resources of the Federal System" and "—Energy Northwest's Net Billed Projects—Net Billing Agreements" and "Bonneville Financial Operations—Statement of Net Billing Obligations and Expenditures."

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 payments by Bonneville under the Lease Agreement, 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." For a discussion of certain proposed and current direct payments by Bonneville for Federal System operations and maintenance, which payments would reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see APPENDIX A - "BONNEVILLE POWER ADMINISTRATION—Bonneville Financial Operations—Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense" and "Developments Relating to Bonneville's Power Marketing Approach and Bonneville's Financial Condition – Fiscal Year 2004 Developments."

THE SERIES 2004 BONDS

General

The Series 2004 Bonds will be issued originally as a single global certificate registered to The Depository Trust Company ("DTC"), or its nominee, Cede & Co., to be held in DTC's book-entry only system. So long as the Series 2004 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 2004 Bonds for all purposes of the Indenture, the Series 2004 Bonds and this Offering Memorandum. Interest on the Series 2004 Bonds will be payable only through participants or indirect participants in DTC so long as the Series 2004 Bonds are held in the book-entry only system. See "Book-Entry Only System" below.

The Series 2004 Bonds will be issued in the aggregate principal amount and will bear interest, computed on the basis of a 360-day year of twelve 30-day months, at the annual rate set forth on the cover page hereof. The Series 2004 Bonds will mature as set forth on the cover page of this Offering Memorandum. The Series 2004 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 2004 Bonds, are referred to as the "Bonds."

Interest on the Series 2004 Bonds will be payable semi-annually on January 1 and July 1 of each year, commencing July 1, 2004, to the persons in whose name the Series 2004 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 2004 Bonds are registered on a special record date established by the Trustee for the payment of such defaulted interest. So long as the Series 2004 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 2004 Bonds.

Book-Entry-Only System

DTC will act as securities depository for the Series 2004 Bonds. The Series 2004 Bonds will be issued as fully-registered Series 2004 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 2004 Bond will be issued for the Series 2004 Bonds, in the aggregate principal amount of such issue, and will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). DTC holds and provides asset servicing for over 2 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 85 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, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Government Securities Clearing Corporation, MBS Clearing Corporation, and Emerging Markets Clearing Corporation, (NSCC, GSCC, MBSCC, and EMCC, also subsidiaries of DTCC, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. 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").

Purchases of the Series 2004 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2004 Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2004 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 2004 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 2004 Bonds, except in the event that use of the book-entry system for the Series 2004 Bonds is discontinued.

To facilitate subsequent transfers, all Series 2004 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 2004 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2004 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2004 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 2004 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the Series 2004 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2004 Bond documents. For example, Beneficial Owners of Series 2004 Bonds may wish to ascertain that the nominee holding the Series 2004 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 2004 BONDS.

Redemption notices will be sent to DTC. If less than all of the Series 2004 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 2004 Bonds unless authorized by a Direct Participant in accordance with DTC's 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 2004 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Series 2004 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 2004 Bonds at any time by giving reasonable notice to the Issuer or the Trustee. In addition, the Issuer, at the direction of Bonneville, may terminate, upon provision of notice to the Trustee and the Tender Agent, the services of DTC with respect to the Series 2004 Bonds. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2004 Bonds are required to be printed and delivered as described in the Indenture.

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 2004 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 2004 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 2004 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 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 2004 BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS OR OWNERS OR REGISTERED HOLDERS OR REGISTERED OWNERS OF THE SERIES 2004 BONDS MEANS CEDE & CO., AS AFORESAID, AND DOES NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2004 BONDS.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2004 Bonds, payment of principal, interest and other payments on the Series 2004 Bonds to Direct and Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Series 2004 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 2004 Bonds are subject to redemption, in whole or in part, on any date, at a Redemption Price equal to the greater of (i) the principal amount thereof, and (ii) the present value of all principal and interest payments on the Series 2004 Bonds to be redeemed scheduled to become due after the date of such redemption, discounted to the redemption date on a semi-annual basis at the "Treasury Rate" plus 12.5 basis points, plus in either case, accrued interest to the redemption date on the Series 2004 Bonds to be redeemed.

"Treasury Rate" means, with respect to any redemption date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date.

"Comparable Treasury Issue" means the U.S. Treasury security selected by a Reference Dealer as having a maturity comparable to the remaining term of the Series 2004 Bonds to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Series 2004 Bonds.

"Comparable Treasury Price" means, with respect to any redemption date, (i) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) on the third business day preceding such redemption date, as set forth in the daily statistical release (or any successor release) published by the Federal Reserve Bank of New York and designated "Composite 3:30 p.m. quotations for U.S. Government Securities" or (ii) if such release (or any successor release) is not published or does not contain such prices on such business day, (A) the average of the Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or (B) if the Trustee is unable to obtain three such Reference Treasury Dealer Quotations, the average of all such quotations.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Dealer and any redemption date, the average, as determined by the Trustee, 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 and Bonneville by such Reference Dealer at 5:00 p.m. (New York time) on the third business day preceding such redemption date.

"Reference Dealer" means (i) either Goldman, Sachs & Co., Citigroup Global Markets Inc. or J.P. Morgan Securities Inc. or their respective successors; provided, however, that if any of the foregoing Reference Dealers shall cease to be a primary U.S. Government securities dealer in New York City (a "Primary Treasury Dealer"), Bonneville (with the approval of the Issuer and the Trustee) shall substitute therefor another Primary Treasury Dealer and (ii) any other Primary Treasury Dealer selected by Bonneville (with the approval of the Issuer and the Trustee).

Selection of Series 2004 Bonds for Redemption; Notice of Redemption

In the event fewer than all of the Series 2004 Bonds are subject to redemption, Series 2004 Bonds shall be selected for redemption (i) by DTC, in accordance with its rules and procedures, so long as DTC or its nominee is the sole registered owner of the Series 2004 Bonds, or (ii) by lot or in such manner as the Trustee may deem fair. While the Series 2004 Bonds are in the book-entry only system, if less than all the Series 2004 Bonds are to be redeemed, DTC's current practice is to determine by lot the amount of the ownership interest of each DTC Participant in the Series 2004 Bonds to be called for redemption, and each DTC Participant is then to select by lot the ownership interest in the Series 2004 Bonds to be redeemed. While Series 2004 Bonds are in the book-entry only system, notice of redemption is required to be given only to DTC and further notices to Beneficial Owners of Series 2004 Bonds will be the responsibility of DTC and the DTC Participants. Any redemption shall be made as provided in the Indenture upon not less than 30 days notice to DTC as sole Bondholder. Notice of optional redemption may state that the redemption is conditioned on deposit of the redemption price with the Trustee on or before the date fixed for redemption and if the redemption price is not so deposited, the redemption notice will be of no force and effect and the Series 2004 Bonds will not be redeemed. No further interest will accrue on the principal of any Series 2004 Bonds called for redemption after the redemption date if payment of the redemption price has been duly provided for, and the registered owners of such Series 2004 Bonds will have no rights with respect to such Series 2004 Bonds nor will they be entitled to the benefits of the Indenture except to receive payment of the redemption price thereof.

THE LEASE AGREEMENT

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

Rental Payments

Bonneville agrees under the Lease Agreement to pay to the Trustee rental payments for deposit in the Bond Fund created under the Indenture in the amounts set forth in a schedule to the Lease Agreement, which schedule provides for rental payments more than sufficient for the payment of the principal of, and interest on, the Series 2004 Bonds. The obligation of Bonneville to make all payments provided in the Lease Agreement is stated to be absolute and unconditional. See "SOURCES OF PAYMENT AND SECURITY FOR THE SERIES 2004 BONDS" herein.

Bonneville has also agreed to pay as additional rent under the Lease 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 Agreement, any estate or interest of the Issuer or Bonneville in the Project, or the rentals under the Lease Agreement during the term of the Lease 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 incurred in connection with the Lease Agreement and to protect, indemnify and hold the Issuer harmless of, from and against (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) 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 Agreement.

Construction and Completion of the Project

The proceeds of the sale of the Series 2004 Bonds will be deposited in the Project Fund established under the Indenture to pay costs of the Project. Bonneville acknowledges that the Issuer is undertaking to construct the Project and that Bonneville will be leasing the Project as it is being constructed. The Issuer agrees that it will suspend, delay or terminate construction of the Project at the direction of Bonneville and will not suspend, delay or terminate construction of the Project other than at the direction of Bonneville. Pursuant to the Construction Agency Agreement the Issuer will engage Bonneville to acquire, construct and equip the Project. Bonneville may, at its option, but shall have no obligation to, construct or complete the Project as lessee under the Lease 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 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 Agreement. Bonneville may suspend or terminate operation of the Project in its discretion, provided that the Lease Agreement shall remain valid, binding and enforceable and there shall be no abatement, postponement or reduction in the rent or other amounts payable by Bonneville under the Lease Agreement.

Covenants

In the Lease 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; 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 2004 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 Agreement.

Damage, Destruction and Condemnation

If the Project is damaged, destroyed or condemned, there will be no reduction in amounts payable under the Lease Agreement. The Issuer shall have no obligation to rebuild, replace, repair or restore the Project. Bonneville will not be obligated to repair or replace the Project or purchase the Project following a loss event so long as the Lease Agreement shall remain valid, binding and enforceable on Bonneville following such loss event. If Bonneville elects to repair or replace the Project, it shall do so with its own funds except to the extent amounts are available in the Construction Account of the Project Fund established under the Indenture for such purpose, in which case it may use such funds. Any proceeds of insurance or condemnation awards received by the Issuer or Bonneville will be deposited into the Construction Account of the Project Fund or the Bond Fund, as agreed to by the Issuer and Bonneville.

Termination of the Lease Agreement

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

Defaults

The Lease 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 that has become due and payable under the Lease Agreement;

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

(c) Failure by Bonneville to observe or perform any covenant, condition or agreement on its part to be observed or performed under the Lease Agreement, other than as referred to in (a) or (b) above, for a period of 30 days after written notice specifying such failure and requesting that it be remedied is given to Bonneville by the Issuer, the Trustee or the holders of more than 25% of the Bonds, or if the failure is such that it cannot be remedied within 30 days, Bonneville fails to proceed to cure with reasonable diligence.

Remedies

Upon the occurrence and continuance of an Event of Default under the Lease 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 rent then due and thereafter to become due, or to enforce performance and observance of any obligations, agreements or covenants of Bonneville under the Lease 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 lease term, 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 Term and to exclude Bonneville from possession of the Project upon the occurrence of an event of default under the Lease Agreement. The Issuer and Bonneville declare that the Lease 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 under the Washington Uniform Commercial Code or otherwise.

Upon the occurrence and continuance of an Event of Default under the Lease Agreement for failure to make rental payments, Bonneville, at the direction of the Issuer, given in its sole discretion, has agreed to promptly surrender use and possession of the Project to the Issuer or a designee of the Issuer.

Statutory Limitation on Legal Remedies Against Bonneville

The Issuer acknowledges in the Lease Agreement that its remedies against Bonneville are limited to those provided under federal law which provide 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 Agreement and not by the market value of the Project or a leasehold interest in the Project.

Options

Under the Lease, Bonneville has the option, at any time and from time to time, to make advance rental payments which, at the direction of Bonneville, will be deposited into the Bond Fund and held to make 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. The Project will be divided into components as provided in the Lease Agreement and Bonneville may exercise its purchase option with respect to any component by making a purchase option payment equal to the redemption price of the percentage of Bonds of the applicable series of the Bonds allocable to such component. Bonneville will exercise its option to make such advance rental payments or such purchase option by delivering a written notice of an authorized representative of Bonneville to the Trustee in accordance with the Indenture, with a copy to the Issuer, setting forth (i) the amount of the advance rental payment or purchase option payment, (ii) the principal amount of Bonds Outstanding requested to be redeemed with such advance rental payment (if any) or purchase option payment (which principal amount shall be in such minimum amount or integral multiple of such amount as shall be permitted in the Indenture), and (iii) the date on which such principal amount of Bonds are to be redeemed. Such advance rental payment to be applied to redeem Bonds or to make any such purchase option payment will be paid to the Trustee in legal tender on or before the redemption date and will be an amount which, when added to the amount on deposit in the Bond Fund and available therefor, will be sufficient to pay the Redemption Price of the Bonds to be redeemed, together with interest to accrue on the Bonds to be redeemed to the date fixed for redemption and all expenses of the Issuer, the Bond Registrar, the Trustee and the Paying Agents (including reasonable fees and expenses of counsel to the Issuer, the Bond Registrar, the Trustee and the Paying Agents) in connection with such redemption. After any purchase of a portion of the Project, the rent payable pursuant to the Lease 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 an appendix to the Lease Agreement) or by such other amount agreed to by the Issuer and Bonneville with the consent of the Trustee; provided that such amount may not be less than an amount sufficient to pay debt service on the Outstanding Bonds when due.

Force Majeure

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

Assignment or Sublease

Bonneville may assign or transfer the Lease Agreement or sublet the whole or any part of the Project so long as (1) Bonneville will remain liable to the Issuer for the payment of all rent and other payments hereunder and for the full performance of all of the terms, covenants and conditions of the Lease Agreement and (2) Bonneville will deliver to the Issuer an opinion of counsel to the effect that such assignment, transfer or sublease will not legally impair in any respect the obligations of Bonneville for the payment of all rents nor for the full performance of all of the terms, covenants and conditions of the Lease Agreement. Bonneville will furnish or cause to be furnished to the Issuer and the Trustee a copy of any such assignment, transfer or sublease in substantially final form at least 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 Agreement.

Amendment

The Lease 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 Agreement".

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 Agreement, including all amounts (excluding payments for indemnification and certain other payments thereunder) to be received by the Issuer pursuant to the Lease Agreement, (ii) all of the right, title and interest of the Issuer in and to the Project, subject to the Lease Agreement, (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 2004 Bonds will be deposited in the Project Fund to be held by the Trustee. Moneys in the Project Fund will be applied to expenses incurred in connection with the issuance and sale of the Series 2004 Bonds and for other costs of the Project upon requisitions signed by an authorized representative of Bonneville.

Bond Fund

The Indenture establishes with the Trustee a Bond Fund into which will be deposited accrued interest, excess Project Fund monies, rents 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.

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

Additional Bonds may be issued under the Indenture from time to time in the discretion of the Issuer for the purpose of providing funds to complete or repair the Project, extend or improve the Project, or to refund outstanding Bonds. It is a condition to the issuance of Additional Bonds that the amounts payable by Bonneville under the Lease Agreement will be adjusted to provide for the payment of the Additional Bonds. Additional Bonds shall be equally and ratably secured under the Indenture with the Series 2004 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 acceleration 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 Agreement.

Pursuant to the Lease 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 anytime, 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 and rescind any declaration of acceleration 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 and premium, if any, 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 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. If the principal of the Bonds has not been declared due, 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. If the principal of the Bonds has been declared due, such amounts will be applied ratably to the payment of unpaid principal and interest, without distinction.

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.

Amendments of the Lease 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 Agreement (a) for the purpose of curing any ambiguity, formal defect or omission therein, (b) which, by the terms of the Lease 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, deletion, extension, repair, replacement, improvement or other change to the description of the Project. The Trustee shall not consent to any other amendment, change or modification of the Lease 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 Agreement with respect to the Bonds.

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 under the Indenture shall cease, terminate and be void and the Trustee shall cancel and discharge the lien and security interests 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; (C) the Issuer shall have delivered to the Trustee either (i) a ruling from the Internal Revenue Service and directed to the Trustee to the effect that the Holders of such Bonds will not recognize income, gain or loss for federal income tax purposes as a result of the Issuer's exercise of its defeasance option and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such option had not been exercised, or (ii) an opinion of counsel from nationally recognized tax counsel to the same effect as the ruling described in clause (i) of this paragraph; (D) the Issuer has delivered an opinion of counsel stating that the deposit shall not result in the Issuer or the Trustee becoming or being deemed to be an "investment company" under the Investment Company Act of 1940; (E) the Issuer has delivered an opinion of counsel from a nationally recognized law firm stating that the Holders of such Bonds (or the Trustee for the benefit of such Holders) shall have a perfected security interest under applicable law in the money or securities so deposited; and (F) 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) through (E) above have been complied with.

UNDERWRITING

Goldman, Sachs & Co. and the other Underwriters (the "Underwriters") of the Series 2004 Bonds have jointly and severally agreed, subject to certain conditions, to purchase the Series 2004 Bonds from the Issuer at an underwriters' discount of $742,407.65 and to reoffer the Series 2004 Bonds at the initial public offering price set forth on the cover page hereof. The Underwriters have agreed to purchase all of the Series 2004 Bonds if any are purchased. The Series 2004 Bonds may be offered and sold to certain dealers (including dealers depositing Series 2004 Bonds into investment accounts) and to others at prices lower than the public offering price set forth on the cover page of this Offering Memorandum. After the Series 2004 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.

ERISA CONSIDERATIONS

Section 406 of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), and/or Section 4975 of the Internal Revenue Code, as amended (the "Code"), restricts or prohibits a pension, profit-sharing or other employee benefit plans, as well as individual retirement accounts and certain types of Keogh plans (each a "Benefit Plan"), from engaging in certain transactions with persons that are "parties in interest" under ERISA or "disqualified persons" under the Code (collectively, "Parties in Interest") with respect to such Benefit Plan. A violation of these "prohibited transaction" rules may result in an excise tax or other penalties and liabilities under ERISA and/or Section 4975 of the Code for such persons.

Certain transactions involving the purchase, holding or transfer of the Series 2004 Bonds might be deemed to constitute prohibited transactions under ERISA and Section 4975 of the Code if the assets of the Issuer were deemed to be assets of a Benefit Plan. Under a regulation (the "Plan Assets Regulation") issued by the United States Department of Labor ("DOL"), the assets of the Issuer would be treated as plan assets of a Benefit Plan for the purposes of applying ERISA and Section 4975 of the Code only if the Benefit Plan acquires an "equity interest" in the Issuer and none of the exceptions contained in the Plan Assets Regulation is applicable. An equity interest is defined under the Plan Assets Regulation as an interest in an entity other than an instrument which is treated as indebtedness under applicable local law and which has no substantial equity features. The Issuer believes that the Series 2004 Bonds should be treated as indebtedness without substantial equity features for purposes of the Plan Assets Regulation. However, without regard to whether the Series 2004 Bonds are treated as an equity interest for such purposes, the acquisition or holding of Series 2004 Bonds by or on behalf of, or with assets of, a Benefit Plan could be considered to give rise to a prohibited transaction if the Issuer, the Trustee, or any of their respective affiliates, is or becomes a Party in Interest with respect to the Benefit Plan. In such case, certain exemptions from the prohibited transaction rules could be applicable, depending on the type and circumstances of the Benefit Plan fiduciary making the decision to acquire a Series 2004 Bond. Included among these exemptions are: DOL Prohibited Transaction Class Exemption ("PTCE") 84-14, regarding transactions effected by "qualified professional asset managers"; PTCE 90-1, regarding investments by insurance company pooled separate accounts; PTCE 91-38 regarding investments by bank collective investment funds; PTCE 95-60, regarding investments by insurance company general accounts; and PTCE 96-23 regarding transactions effected by "in-house asset managers."

ERISA also imposes certain duties on persons who are fiduciaries of Benefit Plans subject to ERISA, including the requirements of investment prudence and diversification, and the requirement that such a Benefit Plan's investments be made in accordance with the documents governing the Benefit Plan. Under ERISA, any person who exercises any authority or control respecting the management or disposition of the assets of a Benefit Plan is considered to be a fiduciary of such Benefit Plan.

Employee benefit plans that are governmental plans (as defined in Section 3(32) of ERISA) and certain church plans (as defined in Section 3(33) of ERISA) are not subject to ERISA requirements, but may be subject to similar requirements under applicable federal or State law.

A Benefit Plan fiduciary considering the purchase of Series 2004 Bonds should consult its tax and/or legal advisors regarding whether the assets of the Issuer would be considered plan assets, the availability of exemptive relief from the prohibited transaction rules and other issues and their potential consequences.

TAX MATTERS

In the opinion of Orrick, Herrington and Sutcliffe LLP, interest on the Series 2004 Bonds is includable in gross income of the holders thereof for federal income tax purposes.

Holders of the Series 2004 Bonds should consult their own tax advisors in determining the federal, state, local and other tax consequences to them of the purchase, ownership and disposition of the Series 2004 Bonds.

LEGAL MATTERS

Legal matters incident to the authorization and issuance of the Series 2004 Bonds are subject to the unqualified approving opinion of Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Issuer by Ropes & Gray LLP 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 Fulbright & Jaworski L.L.P., New York, New York.

(THIS PAGE INTENTIONALLY LEFT BLANK)

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to the Issuer by Bonneville for use in this Offering Memorandum. Such information 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 2004 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in this Offering Memorandum, is true and correct and 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 section and elsewhere in this Offering Memorandum pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

GENERAL

Bonneville was created by an act of Congress in 1937 to market electric power from the Bonneville Dam 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 U.S. 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 30 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin. These projects have an expected aggregate output of roughly 9,000 average megawatts under median water conditions. Bonneville also has acquired and markets power from several non-federally owned and operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by a joint operating agency named Energy Northwest and having a rated capacity of approximately 1100 megawatts. Bonneville sells, purchases and exchanges firm power, non-firm energy, peaking capacity and related power services. Bonneville also constructed and operates and maintains a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities and power marketers.

Bonneville's primary customer service area is the Pacific Northwest. Bonneville estimates that the population of the 300,000 square-mile service area is approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville markets the majority of this power to over 100 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service Bonneville provides to DSIs has diminished substantially relative to historical levels.

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 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 THE POWER AND TRANSMISSION BUSINESS LINES—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 1996, after certain national regulatory initiatives to promote competition in wholesale power markets were announced, Bonneville separated its power marketing function from its transmission system operation and electric system reliability functions. Bonneville remains a single legal entity, but it now conducts its business as separate business lines: the "Power Business Line" and the "Transmission Business Line." See "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines."

Bonneville's cash receipts from all sources, including from both its transmission and power-marketing business lines, must be deposited in 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 is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal 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 Corps and the Bureau for certain costs allocated to 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 2003 payment responsibility to the United States Treasury of $1.057 billion (including $315 million in principal payments in advance of due dates under the Debt Optimization Proposal as described herein) in full and on time. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Proposal."

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 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. Thus, all cash payments of Bonneville other than to the United States Treasury, including payments under the Lease Agreement and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury for the costs described in (i) to (iv) above.

DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION

For much of its history, Bonneville had a high degree of certainty that its revenues from power and transmission services would be sufficient to recover all of its costs without concern for substantial price competition from other suppliers. In the mid-1990's, competition increased in the wholesale electricity industry. Bonneville was particularly affected because its business, both power marketing and the provision of bulk transmission, is primarily wholesale. This increase in competition was due to a number of factors, including electric power deregulation advanced under the National Energy Policy Act of 1992 ("EPA-1992"). As a result of deregulation actions relating to Western energy markets, hydroelectric generating conditions primarily relating to the amount of precipitation in the West, natural gas prices, variations in load levels due to changes in economic activity and the weather, and a variety of other factors, wholesale power prices in the West have been very volatile in the past several years. Prices peaked in the fiscal year 2000-2001 period at levels that were many multiples of historical prices but declined in fiscal year 2002. Prices have since risen somewhat in fiscal year 2003 and in the current fiscal year. Electric power prices affect both the revenues Bonneville receives from disposing of electric power and the expenses Bonneville incurs to meet contracted electric power loads.

Subscription Strategy, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments

At or slightly before the end of Bonneville's fiscal year 2001, which ended on September 30, 2001, all of Bonneville's then existing long-term, in-Region power sales contracts with Preference Customers and DSIs, and all of Bonneville's settlements with Regional investor-owned utilities ("Regional IOUs") to whom Bonneville is required by law to provide Residential Exchange Program benefits expired. (By law Bonneville is required to extend economic benefits of low cost Federal System power to the residential and small farm customers of the Regional IOUs under the Residential Exchange Program. "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program.") In anticipation of the expiration of such contracts and during the unprecedented volatility in Western power markets described herein, Bonneville and its Regional customers negotiated new long-term power sales and related agreements for the period beginning on or slightly before October 1, 2001. Under this "Subscription Strategy," Bonneville entered into five- and ten-year power sales contracts with 135 Regional Preference Customers and into five-year power sales contracts with a small number of DSI companies. Bonneville also entered into settlement contracts with all six of the Regional IOUs to settle Bonneville's obligations under the Residential Exchange Program through fiscal year 2011.

The aggregate power sales commitment initially undertaken by Bonneville under these agreements, together with certain pre-existing surplus firm power sales and related obligations, exceeded by roughly 3200-3300 average megawatts the aggregate amount of power from Federal System generating resources, which was estimated at the time to be roughly 8000 firm average megawatts, and certain contract purchases. To meet a portion of this difference, Bonneville entered into a number of power purchases to augment Federal System generation resources ("Augmentation Purchases"). Given the very high energy prices prevailing at the time, Bonneville subsequently negotiated a number of load reduction agreements with its Regional customers (including DSIs, Regional IOUs and Preference Customers) in lieu of making additional Augmentation Purchases. Under the load reduction agreements Bonneville agreed to pay customers to reduce the amount of power Bonneville otherwise was obligated to provide under related Subscription power sales agreements. Most of the load reductions occurred in fiscal years 2002 and 2003; however, about 700 average megawatts of the load reductions are in effect through fiscal year 2006.

In view of the foregoing Augmentation Purchases and load reduction agreements, lowered expectations regarding Regional load growth, and declining expectations that aluminum company DSIs will meet their power purchase obligations, Bonneville now believes that its firm resources, including existing Augmentation Purchases, could exceed its expected firm load obligations in fiscal years 2004 through 2006. Bonneville therefore believes that it will not have to make substantial additional Augmentation Purchases to meet its Subscription loads through at least fiscal year 2006, subject to changes in contracted loads or anticipated generation from Federal System generating resources, and subject to the receipt of power under existing Augmentation Purchases and other power purchase and related agreements. While the foregoing circumstances now mean that in general Bonneville expects to have little need to acquire additional power to meet loads, Bonneville may have a relatively modest amount of firm power in excess of actual firm loads through fiscal year 2006 and may have some market price risk in making discretionary power sales of that excess firm power.

In fiscal years 2000-2001, coincident with the development of the power sales and related contracts under the Subscription Strategy, Bonneville developed and proposed power rates for such Subscription agreements for the five-year period beginning October 1, 2001 (the "2002 Final Power Rates"). The 2002 Final Power Rates are comprised of "base rates" and certain rate level adjustment mechanisms. FERC approved the proposed 2002 Final Power Rates, including the base rates and the rate level adjustment mechanisms, on July 21, 2003. FERC's review and confirmation of the 2002 Final Power Rates are subject to legal challenge in the Ninth Circuit Court and a number of customers have challenged approval of the 2002 Final Power Rates in that court. "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

The "base rates" are subject to three intra-rate-period rate level adjustments that are triggered upon the occurrence of specified circumstances. The base rates are between approximately 1.93 cents per kilowatt-hour and 2.30 cents per kilowatt-hour, excluding transmission and depending on type of service, and are at levels similar to those in effect for like service in the fiscal year 1997-2001 rate period. While the base rates are low relative to the cost of most other power generation, the triggering of the rate level adjustment mechanisms (which in effect create variable rate levels for affected power sales and related transactions) has had the effect of raising Bonneville's rates substantially over the base rates.

Under the first of the rate adjustment mechanisms, the Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), Bonneville makes semi-annual adjustments to rate levels tied to the direct cost of certain Augmentation Purchases and certain load reduction agreements entered into to address the increment of loads assumed by Bonneville under the Subscription Strategy.

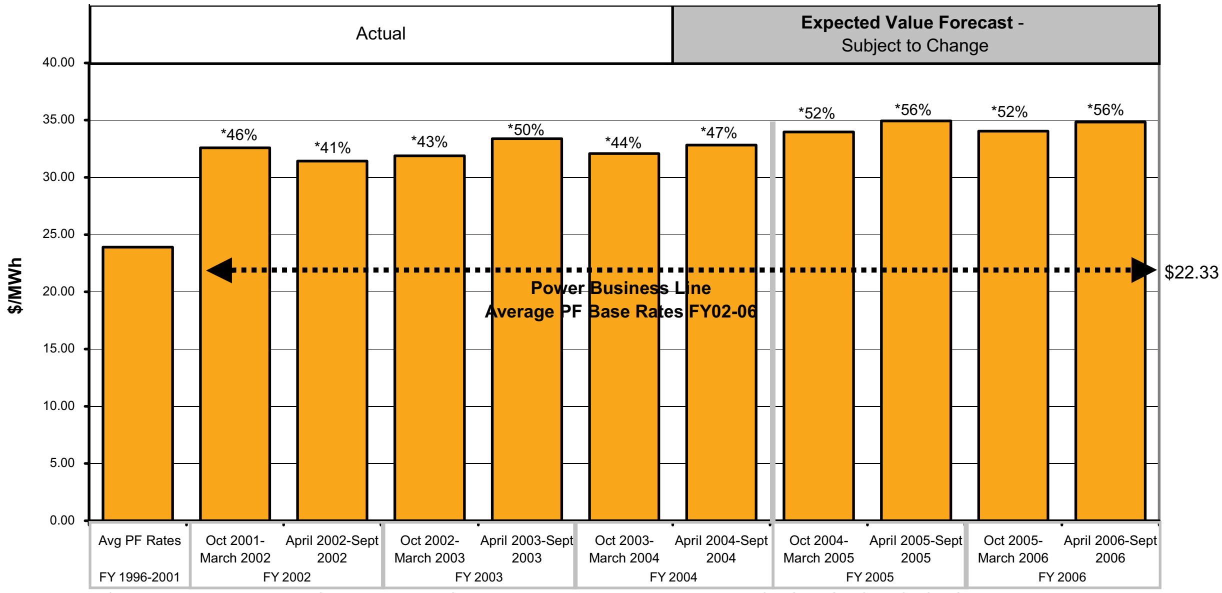
Under the second rate level adjustment, the Financial Based Cost Recovery Adjustment Clause ("FB-CRAC"), Bonneville increases rate levels on an annual basis to obtain limited amounts of revenues in a fiscal year if Bonneville forecasts that its Power Business Line accumulated net revenues will be below identified fiscal year end threshold levels.

Under the third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause ("SN-CRAC"), Bonneville may impose one or more separate rate level increases in order to recover costs on a temporary basis if certain conditions indicating that Bonneville is not adequately recovering its costs are met. In early calendar year 2003, Bonneville determined that the conditions triggering an SN-CRAC proceeding had been met and later developed and formally proposed a specific SN-CRAC rate level adjustment to be effective for fiscal years 2004 through 2006. Bonneville submitted the final record of decision and the final SN-CRAC rate level adjustment proposal to FERC for its review and approval. The proposal remains under review by FERC.

The final SN-CRAC rate level adjustment proposal calls for the SN-CRAC rate level adjustment for each of fiscal years 2004 through 2006 to be made on the basis of the Power Business Line's third quarter projected net revenues for the respective prior fiscal year. Under the record of decision, certain costs in a number of major cost categories would be capped and would not be automatically recovered through the final proposed SN-CRAC rate level adjustment. The maximum revenue recoverable through the proposed SN-CRAC rate level adjustment in fiscal years 2004-2006 would be capped at $320 million per year. In addition, Bonneville would provide a refund to customers from previously collected revenue if Bonneville's Power Business Line accumulated net revenues exceed established threshold levels.

The following Table depicts the cumulative effects of the base rate and the three rate adjustment mechanisms on Bonneville's average Subscription power rate levels for full requirements service at Bonneville's PF rate on both a historical and forecasted basis. See "POWER BUSINESS LINE – Customers and Other Power Contract Parties of Bonneville's Power Business Line." The rates portrayed below do not include requirements service provided to certain small Preference Customers who committed to purchase power from Bonneville early in the Subscription process at power rates that are not subject to the cost recovery adjustment mechanisms. The depiction below portrays only full requirements service offered under Bonneville's Subscription power rates schedules and does not portray rate levels related to Slice of the System, Partial Requirements, DSI and Regional IOU Exchange Settlements. Nonetheless, Bonneville believes it illustrates the impacts of the rate adjustments in the current rate period and provides a basis to compare Subscription power rates with rate levels in the prior rate period.

Bonneville Full Requirements Power Rate Levels FY 1996-2007,
Including Actual and Forecasted Cumulative Rate Level Adjustments in FY 2002-2006



*Each bar represents the average full requirements rate for the indicated period, taking into account the LB-CRAC, FB-CRAC and SN-CRAC. The percentage presented above each bar is the adjusted rate over Base Rates taking into account the LB-CRAC, SN-CRAC and FB-CRAC. These forecasted rates reflect updated August numbers.

Bonneville estimates that the proposed SN-CRAC rate level adjustment would provide Bonneville with an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time over the three fiscal years beginning October 1, 2003. Such estimates are based on a number of forecasts and assumptions, which may not be realized. Notwithstanding the SN-CRAC rate level adjustment proposed by Bonneville, Bonneville has reserved the ability to develop an additional SN-CRAC rate level adjustment mechanism during the five-year rate period. Whether and the extent to which Bonneville would increase rate levels under an additional SN-CRAC adjustment would be determined in view of all facts and circumstances at the time.

While FERC has approved the 2002 Final Power Rates, including the SN-CRAC mechanism as a general proposition, the detailed SN-CRAC rate level adjustment proposal finalized by Bonneville in June 2003 is under review by FERC as a separate matter and Bonneville awaits final approval thereof. Several of Bonneville's customers and customer groups have filed separate suits in the Ninth Circuit Court challenging Bonneville's decision to initiate the proceedings necessary for implementing the SN-CRAC. These parties are seeking to set aside Bonneville's finding that the SN-CRAC has triggered. If successful, the litigation could result in a remand by the court to Bonneville of the decision that the conditions permitting Bonneville to adjust its power rates under the SN-CRAC provisions of the 2002 Final Power Rates have been met. The petitioners have not sought expedited review by or injunctive relief from the court in this matter. As noted above, a number of customers have entered a legal challenge to FERC's approval of the 2002 Final Power Rates Proposal.

Under current internal forecasts of future market prices, Bonneville believes that its Subscription power rates levels, as adjusted by the various rate level adjustment mechanisms, on average in fiscal years 2004-2006 will be at or near average market prices for such period based on similar power products. Bonneville believes that its Subscription power rates will not exceed the cost of new natural gas fired generation when shaped to serve load similar to the shaping ability of the Federal System. Such belief is based on market, rate and other forecasts that are subject to many variables most of which are not within Bonneville's control.

For a more detailed description of Bonneville's proposal for power rates applicable to Subscription power sales, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates."

Bonneville's Fiscal Year 2003 Financial Results

According to final audited results for the fiscal year ended September 30, 2003 ("Fiscal Year 2003"), Bonneville made payments to the United States Treasury of $1.057 billion, which included full and timely payments of Bonneville's scheduled repayment responsibilities and $315 million in advance amortization of debt under the Debt Optimization Proposal. For a description of the Debt Optimization Proposal see "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Proposal." Bonneville also recorded positive net revenues of approximately $555 million, although absent the net revenue effects of the Debt Optimization Proposal and other debt management actions relating to Energy Northwest, Bonneville had net revenues of $37 million. The fiscal year end net revenues also excludes $85 million in non-cash, mark-to-market accounting adjustments under the Financial Accounting Standards Board Statement of Accounting Standard No. 133. In addition, Bonneville had $511 million in fiscal year end financial reserves. Of that $511 million, approximately $233 million are attributable to actions taken throughout the fiscal year to assure financial liquidity. These actions deferred payments into the future, creating future cash obligations and delaying cash disbursements. By way of contrast, in fiscal year 2002, Bonneville made payments to the United States Treasury in the amount of $1.056 billion (including $266 million in advance amortization of debt under the Debt Optimization Proposal) and recorded net revenues of about $9.5 million. However, Bonneville recorded a net operating loss of about $348 million after excluding the positive net revenue effects of the Debt Optimization Proposal and other Energy Northwest debt management actions. In addition, Bonneville closed fiscal year 2002 with financial reserves in the amount of approximately $188 million.

Bonneville's financial reserves include cash and "deferred borrowing." Deferred borrowing represents amounts that Bonneville is authorized to borrow from the United States Treasury for expenditures that Bonneville has incurred to date but the borrowing for which Bonneville has elected to delay.

A number of elements contributed to Bonneville's financial performance in fiscal year 2003. First, with indications in early calendar year 2002 that revenues from discretionary power sales in such year would be lower than previously forecasted, Bonneville began reducing its costs substantially. Bonneville continued to do so in fiscal year 2003. Through expense reductions, deferrals and other actions, Bonneville reduced costs in fiscal year 2003 by about $200 million, and expects that the cost reduction program will improve its Power Business Line financial condition by $350 million in aggregate over the fiscal year 2003-2006 period. Bonneville continues to explore additional cost reductions and deferrals.

Second, in fiscal year 2003 Bonneville received a total of about $175 million of United States Treasury repayment credits, most of which are derived under section 4(h)(10)(C) of the Northwest Power Act. These credits are provided to reimburse Bonneville for certain fish and wildlife costs incurred by Bonneville, including power purchases made by Bonneville that are attributable to the effects of operating the hydroelectric system for the benefit of fish. Bonneville's United States Treasury repayment credits for fiscal year 2003 included $78.7 million from the Fish Cost Contingency Fund, which represented credits available to Bonneville for fish and wildlife costs on behalf of non-power uses of the federal dams in years prior to fiscal year 1995. Of the remaining $97.3 million in fish and wildlife credits, virtually all were provided for applicable fish and wildlife costs borne by Bonneville in fiscal year 2003. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

Third, Bonneville triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2003. This rate level adjustment allowed Bonneville to recover about $90 million in additional revenues in fiscal year 2003, after taking into account certain effects related to the Slice of the System contracts described herein. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001." The FB-CRAC had the effect of raising the average rates for those power sales and related contracts to which the adjustment applies by about 11 percent over applicable base rates. The rate level increases under the FB-CRAC are in addition to rate level increases in effect under the LB-CRAC. Bonneville set the net LB-CRAC adjustment at about 32 percent of base rates for the first six months of fiscal year 2003 and at about 39 percent of base rates for the second six months of the fiscal year.

Fourth, after taking into account the effects of the various rate level adjustments under the Final 2002 Power Rate Proposal, as described herein, Bonneville's affected Subscription Power rates in fiscal year 2003 remained at levels comparable to those in effect in fiscal year 2002.

Fifth, despite water conditions in the Pacific Northwest that were 85 percent of average, Bonneville's revenues from discretionary power sales increased because of higher market prices for such power.

For a discussion of year-to-year financial results see "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results."

Fiscal Year 2004 Developments

Bonneville's Unaudited Fiscal Year 2004 First Quarter Results and First Quarter Fiscal Year-End Forecast

When compared to the first quarter of fiscal year 2003, total operating expense decreased by $121 million (roughly 17 percent), primarily because of decreased operations and maintenance expense and purchased power. In addition, revenues from electricity sales and transmission declined by $84 million (or roughly 10 percent), when compared to the first quarter of fiscal year 2003, primarily as a result of lower secondary power revenues and after excluding the effects of the accounting treatment for derivative instruments and hedging. Bonneville's cash balance at the end of the fiscal year 2004 first quarter was $584 million, compared with $240 million for the same period in fiscal year 2003. For further detail see Appendix B-2 "FEDERAL SYSTEM UNAUDITED FINANCIAL STATEMENTS FOR THE THREE MONTHS ENDED DECEMBER 31, 2003."

In addition, based on various expectations and assumptions, Bonneville's first quarter review indicates that Bonneville has a high degree of certainty that it will make its planned fiscal year 2004 annual United States Treasury payments in full and on time. These planned payments include planned early amortization of about $346 million principal amount of United States Treasury repayment obligations under the Debt Optimization Proposal, described herein. Among the factors contributing to this expectation are the comparatively high level of reserves currently in the Bonneville Fund, the continuing effects of the various cost recovery adjustment rate mechanisms described herein, low exposure to purchased power expense to meet committed loads, and lowered interest expense and operating expenses. Additionally, forecasts of water conditions in the Region prepared outside of, but relied on by Bonneville, indicate precipitation will be below average levels, which is expected to result in less than average amounts of hydroelectric generation and related discretionary power sales. Electric power prices for and the expected revenues from discretionary power sales, however, have been and may continue to be somewhat lower than Bonneville forecasted in developing the SN-CRAC rate level adjustment mechanism in calendar year 2003. Nonetheless, the SN-CRAC rate level adjustment mechanism was designed to address a broad range of variability in revenues from discretionary power sales, and the lowered forecast of such revenues is not expected to affect materially Bonneville's ability to meet its fiscal year 2004 payments to the United States Treasury. The foregoing expectations and forecasts are subject to many variables and assumptions and therefore may not be realized.

Within Fiscal Year Prepayments of Appropriations Repayment Obligations

As part of Bonneville's continuing effort to control costs Bonneville has examined a number of internal proposals to improve its cash management. One opportunity that Bonneville has examined is the prepayment within a fiscal year of certain outstanding appropriations repayment obligations that would otherwise be repaid at the end of such fiscal year. Depending on circumstances at the time, such prepayments may enable Bonneville to obtain net interest savings because interest earnings on amounts in the Bonneville Fund may be lower than the interest accruing on the related appropriations repayment obligations.

The prepayments at issue relate to Bonneville's repayment obligations for Federal System appropriations associated with investments that have reached the end of their designated useful lives and are thus "due" for repayment. By law, Bonneville is to set its power and transmission rates to recover revenues sufficient to assure repayment of such appropriated investments within their designated useful lives, as established in some cases by statute and in other cases by administrative policy reflected in Secretary of Energy's directive RA 6120.2. Bonneville refers to such repayment obligations as "due appropriations repayment obligations." They can be contrasted with other appropriation repayments, which, by operation of administrative policy reflected in Secretary of Energy's directive RA 6120.2, may become scheduled for repayment in advance of the end of their repayment periods. Bonneville does not propose to prepay within a fiscal year such scheduled, but not due, repayment obligations.

While Bonneville has historically made intra-fiscal-year payments with respect to due payments on bonds issued to the United States Treasury, in great part for scheduled semi-annual interest payments on such bonds, the prepayment of due appropriations repayment obligations within a fiscal year would depart from Bonneville's historical practice. Under historical practice Bonneville would pay such due appropriations repayment obligations only at the end of a fiscal year. By contrast to historical practice, within-fiscal-year prepayments of due appropriations repayment obligations would reduce the reserves in the Bonneville Fund available to meet non-Federal obligations during the remainder of the subject fiscal year to the extent of such prepayments. Nonetheless, the interest savings would increase Bonneville's financial reserves over what they otherwise would have been at the end of the subject fiscal year.

In the second quarter of fiscal year 2004, Bonneville prepaid by about eight months approximately $73 million principal amount of appropriations repayment obligations that were due at the end of this fiscal year. Prior to making the above mentioned prepayment, Bonneville concluded that it had in excess of a 99 percent probability of making its full scheduled fiscal year 2004 payments to the United States Treasury and a slightly greater probability of making the subject appropriations repayment obligations in full in fiscal year 2004, after taking into account the interest savings to be achieved through early payment.

Bonneville has yet to determine whether and the circumstances under which it would take advantage of similar interest savings opportunities in future fiscal years. Bonneville estimates it will have between $10 and $110 million per year in due appropriations repayment obligations over the next five years bearing interest at rates that may offer similar interest savings opportunities. Whether and the extent to which Bonneville will make similar advance payments of due appropriations obligations in the future will depend on the facts and circumstance at the time, but Bonneville expects it will do so only in years when it would have a near certainty of meeting its annual repayment obligations in full to the United States Treasury. Under U.S. Department of Energy repayment policy, Secretary of Energy's directive RA 6120.2, due appropriation repayment obligations have the highest priority for payment among all of Bonneville's appropriation repayment responsibilities and hence would be the last of such payments to be rescheduled if Bonneville were to miss scheduled payments to the United States Treasury. For a brief discussion of Secretary of Energy's directive RA 6120.2 see "BONNEILLE FINANCIAL OPERATIONS—The Federal System Investment" and "—Order in Which Bonneville's Costs Are Met."

For a discussion of the effects of intra-fiscal-year payments relating to the Corps, Bureau and certain other expenses see "BONNEVILLE FINANCIAL OPERATIONS—Direct Funding of Federal System Operations and Maintenance Expense."

President's Fiscal Year 2005 Budget

On February 2, 2004, President Bush issued the budget for Federal Government for fiscal year 2005. The budget narrative refers to the proposed use by Bonneville of lease purchase arrangements such as the Lease. The narrative states that Bonneville's "debt to the U.S. Treasury is currently limited by statute. To ensure the integrity and usefulness of this limitation, the Administration is considering proposing legislation calling for certain non-traditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville]'s statutory debt limit. This legislative proposal will be fully vetted with [Bonneville] stakeholders."

Bonneville understands that such a proposal would be intended to limit future transactions only and would not affect its obligations under the Lease. Bonneville expects to participate in the preparation of any such legislative proposal.

Power Marketing After Fiscal Year 2006

Bonneville currently estimates that its contracted-for loads and resources are in rough balance from fiscal year 2004 through fiscal year 2006, with Bonneville having a relatively modest surplus of power under critical water assumptions.

After fiscal year 2006, however, Bonneville faces some uncertainty with regard to the amount of power loads Bonneville will be required to meet and hence the amount of power it may have to obtain in addition to existing

Federal System generating resources. Bonneville currently has about 1000 average megawatts of Augmentation Purchases, which will decline to about 800 average megawatts by fiscal year 2006 before expiring at or near the end of fiscal year 2006. In addition, all of the remaining contractually-committed take or pay power purchases by aluminum company DSIs (originally in the amount of 1500 average megawatts although Bonneville is currently selling only about 200-300 average megawatts to such DSIs) will expire at the end of fiscal year 2006. Moreover, in developing the Subscription Strategy in calendar years 1999-2001, Bonneville assumed that it would meet through physical power sales about 2200 average megawatts of Regional IOU residential and small farm loads after fiscal year 2006 under the Regional IOU Exchange Settlements. Under those Settlements, Bonneville has reserved the unilateral right to determine how much of its Regional IOU Exchange Settlement obligation will be met through physical sales of power to Regional IOUs versus the payment of monetary benefits to Regional IOUs. Finally, while a large portion of the existing Regional Preference Customer Subscription power sales remain in effect through fiscal year 2011, about 800 average megawatts of such load are under contract only through fiscal year 2006. Bonneville's Final 2002 Power Rates will expire at the end of fiscal year 2006. Rate levels in the period after fiscal year 2006 will affect the inclination that such customers may have to increase or decrease the amount of loads they place on Bonneville.

Under critical water assumptions, Bonneville currently estimates that if (i) Bonneville were to have no physical power sales to aluminum company DSIs or to Regional IOUs under the Regional IOU Exchange Settlement after 2006, (ii) existing, long-term, non-Subscription power sales and similar arrangements remain in effect, (iii) existing power sales to Regional Preference customers remain in effect, with forecasted load growth under partial and full requirements contracts, and (iv) current forecasts of the output of Federal System generating resources are realized, Bonneville may have a small firm power deficit of less than 100 average megawatts in fiscal years 2007 and 2008, increasing, roughly, to about 240 average megawatts in fiscal year 2009, 185 average megawatts in fiscal year 2010 and 320 average megawatts in fiscal year 2011. Bonneville views these possible deficits as relatively modest in view of the Federal System's firm power capability of in excess of 8000 average megawatts under critical water assumptions. However, if Bonneville were to enter into physical power sales obligations to Regional IOUs to effect the Regional IOU Exchange Settlements and/or to DSIs or others, without corresponding reductions in power sales to Regional Preference Customers, Bonneville could have larger generating resource deficits. This could increase the amount of power purchases that Bonneville would otherwise have to make, perhaps substantially depending on the amount of the resulting resource deficit.

In view of the uncertainties surrounding the period after fiscal year 2006, in calendar year 2002, Bonneville and its customers initiated a Regional discussion ("Regional Dialogue"). The Regional Dialogue seeks to address Bonneville's role in meeting Regional load obligations in the future. In the context of the Regional Dialogue, Bonneville has indicated to Regional customers its concerns that it not be placed in the position of attempting to acquire a substantial portion of the Region's power needs, as occurred in calendar year 2001 during the West Coast energy crisis.

In a letter dated December 9, 2003, to the Pacific Northwest Electric Power and Conservation Planning Council (the "Council"), an entity established by Congress to guide electric power planning in the Region, Bonneville reiterated that one of Bonneville's goals is to provide stable, low-cost power rates and benefits to the Region after fiscal year 2006. For a discussion of the Council see "POWER BUSINESS LINE—Bonneville's Authority to Add Resources" and "—Fish and Wildlife," herein. Bonneville stated that it would prefer to achieve these objectives by limiting the incremental load obligations Bonneville would bear above existing Federal System generating resources. As a means of balancing its statutory obligation to meet loads placed on it by Preference and Regional IOU customers with the goal of low, stable power rates, Bonneville indicated to the Council that Bonneville would prefer to have customers in the Region assume the role of meeting incremental power needs. Bonneville also stated that it viewed positively a Council proposal to limit the amount of firm power sales Bonneville makes at embedded cost rates to roughly the output of the existing Federal System. Bonneville also stated that a "tiered rate" design for the Subscription power sales in the period after 2006 would be a means of achieving this end. Under tiered rates, costs of new power purchases above the existing Federal System generating resources would not be melded with the comparatively low embedded costs of Federal System resources. Rather, the costs of the new power purchases would be separately recovered under an additional power rate or rate mechanism. To the extent a customer's purchases from Bonneville would be allocated for recovery under such a rate or rate mechanism, then, the customer would bear the costs of the related incremental power purchases.

The ultimate load obligation that Bonneville will assume will depend on a number of factors, including the outcome of the Regional Dialogue, and hence is uncertain. Bonneville does not anticipate finally resolving its load obligations in the post-fiscal year 2006 period until at least fiscal year 2005.

POWER BUSINESS LINE

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 Business Line—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 Bonneville-owned transmission system and certain other features, constitute the Federal System. The Federal System includes those portions of the federal investment in the Regional hydroelectric projects that have been allocated to power generation. Such projects were constructed and are operated by the Corps or the Bureau. 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 other power suppliers.

Federal Hydro Generation

Hydropower from federally-owned hydroelectric projects currently supplies approximately 67% of Bonneville's firm power supply. Bonneville also has acquired a small amount of power from non-federally-owned hydroelectric projects. 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. See the table entitled "Operating Federal System Projects for Operating Year 2004."

The amount of electric power produced by a hydropower-based system such as the Federal System varies with annual precipitation and weather conditions. This variability has led Bonneville to classify power it has available into two types, firm power and seasonal surplus energy (as described below) based on certainty of occurrence.

Bonneville defines "firm power" as electric power that (i) is continuously available from the Federal System even during the most adverse water conditions, and (ii) is useful for meeting Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e.*, the worst low-water period on record for the Columbia River Basin. Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity and firm energy. 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 2004, the Federal System, including firm energy purchases, would be capable of producing about 9,926 average megawatts of firm energy under certain assumptions of low water conditions. In conducting loads and resources evaluations Bonneville utilizes the term "operating year," meaning the twelve calendar months beginning each August 1. See the following table "Operating Federal System Projects For Operating Year 2004."

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most water years. Bonneville estimates that in most months 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 most new resources added to meet firm energy needs will also contribute more peaking capacity. As a result, Bonneville's resource planning focuses on the need to develop sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal-, gas-, oil- and nuclear-based generating systems must focus their resource planning on having enough peaking capacity to meet peak loads.

Bonneville markets most of its energy on a firm basis. However, the amount of energy that the Federal System can produce varies from period to period and depends on a number of factors, including weather conditions, streamflows, storage conditions, flood control needs, and fish and wildlife requirements.

In general, for long-term resource planning purposes Bonneville estimates the amount of electric power it will acquire to meet loads above the firm power that the Federal System is expected to generate under certain low water conditions. 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 average water conditions. The energy that Bonneville has to market above critical water assumptions in a specified period is referred to as seasonal surplus energy. The amount of seasonal surplus energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. During median water years, the Federal System would generate seasonal surplus energy of about 2700 annual average megawatts, while in wet years the amount of such energy available may average in some months as much as 4300 annual average megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small.

Under the Slice of the System contracts for the ten years beginning October 1, 2001, Slice customers purchased from Bonneville, for their requirements, an aggregate 22.63 percent proportionate interest of the output of the Federal System at a power rate intended to recover the same proportion of identified Federal System generating costs. This purchase includes firm power and what would otherwise be seasonal surplus energy from the Federal System in the same proportion. See "—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads." Thus, Bonneville believes that its power sales revenues from seasonal surplus energy are somewhat less subject to the impact of hydroelectric generation variability and market prices, than was the case prior to the commencement of sales under the Slice of the System contracts.

The Corps and the Bureau operate the federally-owned hydroelectric projects in the Region to serve multiple statutory purposes. These purposes may include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection and 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 amount of power it has available to market from these projects.

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table reflects measures under the biological opinions (and supplements thereto) issued with respect to the Federal System beginning in 1995, in each case under the Endangered Species Act ("ESA"), including measures from the 2000 Biological Opinion and a biological opinion issued by the U.S. Fish and Wildlife Service ("Fish and Wildlife Service") in 2000. As new biological opinions and similar constraints are introduced to the hydropower system, those changes will be reflected in the availability of Federal hydropower under all water conditions. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife."

Other Generating Resources

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station owned and operated by Energy Northwest, a joint operating agency. The Columbia Generating Station has the largest capacity for energy production of the non-federal resources. In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. The amount of power purchased under these contracts has increased substantially from prior years as Bonneville has used such contracts to obtain electric power needed to meet the increased loads taken on by Bonneville under the Subscription Strategy.

Operating Federal System Projects For Operating Year 2004

In all years, the energy generating capability of the Federal System's hydroelectric projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities and stream flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a fifty-year record of river flows based on the period from 1929-1978 for planning purposes. During this historical period, low water conditions ("Low Flows") occurred in 1936-37, median water conditions ("Median Flows") occurred in 1957-58 and high water conditions ("High Flows") occurred in 1973-74. Bonneville estimates the energy generating capability of Federal System hydroelectric projects in an Operating Year (August 1 to July 30) by assuming that these historical water conditions were to occur in that Operating Year and making adjustments in the expected generating capability to reflect the current physical capacity operating limitations and current stream flow 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 2004, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Flows, Median Flows and High Flows. 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 and assumed plant capacity factors.

Operating Federal System Projects For Operating Year 2004[1]

Project	Initial Year in Service	No. of Generating Units	January Capacity (Peak MW)[2]	Maximum Energy (aMW)[3]	Median Energy (aMW)[4]	Firm Energy (aMW)[5]
United States Bureau of Reclamation Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	5,748	3,110	2,433	1,929
Hungry Horse	1952	4	281	126	101	77
Other Bureau Projects[6]		16	225	163	156	130
1. Total USBR Projects		53	6,254	3,399	2,690	2,136
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,155	1,660	1,338	1,061
John Day	1968	16	2,037	1,479	1,108	802
The Dalles including Fishway[7]	1957	24	1,752	1,068	822	594
Bonneville including Fishway	1938	20	839	594	540	362
McNary	1953	14	947	734	690	518
Lower Granite	1975	6	690	459	345	221
Lower Monumental	1969	6	677	449	315	223
Little Goose	1970	6	734	453	334	218
Ice Harbor	1961	6	540	361	246	138
Libby	1975	5	549	300	220	167
Dworshak	1974	3	422	233	188	126
Other Corps Projects[8]		20	398	295	269	225
2. Total USACE Projects		153	11,740	8,095	6,415	4,655
3. Total USBR and USACE Projects (line 1 + line 2)		**206**	**17,994**	**11,494**	**9,105**	**6,791**
Non-Federally-Owned Projects						
Columbia Generating Station	1984	1	1,150	1,000	1,000	1,000
Other Non-Federal Hydro Projects[9]		5	32	59	47	45
Other Non-Federal Non-Hydro Projects[10]		13	65	121	121	121
4. Total Non-Federally-Owned Projects		**19**	**1,247**	**1,180**	**1,168**	**1,166**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases[11]		**n/a**	**1,844**	**1,969**	**1,969**	**1,969**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**225**	**21,085**	**14,643**	**12,242**	**9,926**

Source: 2002 Pacific Northwest Loads and Resources Study, Bonneville, December 2002.

(1) Operating Year 2004 is August 1, 2003 through July 31, 2004.

(2) January capacity is the maximum generation to be produced under Low Flows in megawatts of capacity. January is a benchmark month for the system peaking capability because of the potential for high peak loads during January due to winter weather.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Flows in average megawatts of energy. The hydroregulation studies for this analysis contain measures from biological opinions from and after 1995.

(4) Median energy capability is the estimated amount of hydro energy to be produced using Median Flows in average megawatts of energy.

(5) Firm energy capability is the estimated amount of hydro energy to be produced using Low Flows in average megawatts of energy.

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

(7) The Dalles Project is portrayed here for convenience as including the Dalles Fishway Project of 4 megawatts of peaking capacity and 3 average megawatts of energy. The Dalles Project in fact is non-Federally-owned.

(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).

(9) Other Non-Federal Hydro Projects include the following hydroelectric projects estimated by water conditions: Mission Valley's Big Creek (1981), Lewis County PUD's Cowlitz Falls (1994), and the City of Idaho Falls' Idaho Falls Project (1982).

(10) Other Non-Federal Projects include the following projects: the Western Generation Agency's James River Wauna Cogeneration Project (1996), the State of Idaho DWR's Clearwater hydro (1998) and Dworshak Small Hydro (2000) projects. U.S. Park Service's Glines Canyon (1927) and Elwah (1910) hydro projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing and Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, Calpine's Fourmile Hill Geothermal project, and a share of the City of Ashland's solar project.

(11) Bonneville Contract Purchases include: Subscription Strategy Augmentation Purchases and other contracts by Bonneville for power from both inside and outside the Region, including Canada.

Energy Northwest's Net Billed Projects

Set forth below is a description of certain nuclear generating stations undertaken by Energy Northwest, a joint operating agency formed under the laws of the State of Washington. Bonneville has acquired the entire project capability of Energy Northwest's Project 1 and Columbia Generating Station. Bonneville has also acquired all of the project capability associated with Energy Northwest's 70% ownership interest in Project 3. The Columbia Generating Station is an operating facility but Project 1 and Project 3 were terminated in the 1990s, prior to construction completion. These three projects are referred to as the "Net Billed Projects." Bonneville has also acquired the entire project capability associated with the City of Eugene, Oregon, Water and Electric Board's ("EWEB") 30% ownership interest in the now terminated Trojan Nuclear Project ("Trojan"), operated by and co-owned with Portland General Electric Company. The costs of the foregoing projects are secured by payments and net billing credits from Bonneville, as described herein.

Energy Northwest Net Billing Agreements. 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 (the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its 70% ownership interest in 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 (the "Project 3 Net Billing Agreements" which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project.

Each Project 1, Columbia and Project 3 Participant assigned its share of Project capability to Bonneville under a Project 1 Net Billing Agreement, Columbia Net Billing Agreement and Project 3 Net Billing Agreement, respectively.

Under the Net Billing Agreements, in payment for the share of the capability of each Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement or accounting 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 cash payments. 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.

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

Net Billed Projects. The Columbia Generating Station ("Columbia") is an operating nuclear electric generating station located about 160 miles southeast of Seattle, Washington, near Richland, Washington on DOE's Hanford Reservation. The site has been leased from DOE for a term of 50 years commencing July 1, 1972, with options to extend the lease for two consecutive ten-year periods.

Columbia commenced commercial operation in 1984 and has a net design electrical rating of 1,153 megawatts. Columbia consists of a General Electric Company-designed boiling water reactor and nuclear steam supply system, a Westinghouse turbine-generator and the necessary transformer, switching and transmission facilities to deliver the output to the transmission facilities of the Federal System located in the vicinity of Columbia. The entire capability of Columbia has been acquired by Bonneville under the Columbia Net Billing Agreements.

Project 1 is a terminated, partially completed nuclear electric generating project located about 160 miles southeast of Seattle, Washington, on DOE's Hanford Reservation, approximately one and one-half miles east of Columbia. In May 1994, Energy Northwest's Board of Directors adopted a resolution terminating Project 1. After termination, Energy Northwest proceeded to offer for sale assets in the form of uninstalled operating equipment and construction materials in light of the fact that there was no market for the sale of Project 1 in its entirety. Certain of these assets have been sold. Energy Northwest has been planning for the demolition of Project 1 and restoration of the site.

Project 3 is a terminated, partially complete nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington. In May 1994, Energy Northwest's Board of Directors adopted a resolution requesting the termination of Project 3. Project 3 was terminated in June 1994. Virtually all of the remaining project assets have been sold and the site ownership has been transferred to a county development entity.

Site Restoration of Project 1. Energy Northwest's Project 1 shares a common site lease from DOE with Energy Northwest's terminated Nuclear Project No. 4 (Project 4). Project 4 is one of two generating stations for which Energy Northwest (formerly, Washington Public Power Supply System) issued bonds that were subsequently unpaid and placed in default when the Washington State Supreme Court found that certain underlying contracts among various utility participants (not including Bonneville) were invalid under Washington State law. Since Project 4 has virtually no assets to fund site restoration and because it shares a common site lease with Project 1, there is some uncertainty in the view of the Washington State Energy Facilities Siting Council ("EFSEC") about the legal responsibility that Project 1 may have for Project 4 site restoration.

Site restoration requirements for Projects 1 and 4 are governed by site certification agreements between Energy Northwest and the State of Washington and regulations adopted by EFSEC, as well as a site and a lease agreement with DOE. Energy Northwest submitted a site restoration plan to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment or other techniques such that the sites pose minimal hazard to the public. EFSEC conditionally approved the site restoration plan on June 12, 1995. Updated site restoration plans were submitted in 1999 and most recently in 2002.

On December 3, 2003, Bonneville, Energy Northwest, EFSEC and DOE executed an agreement concerning site restoration for Projects 1 and 4. The agreement requires Bonneville to fund site remediation of Projects 1 and 4, largely involving eventual encapsulation of major structures at the two Projects. With the exception of limited near-term remediation designed to maintain Projects 1 and 4 in "safe storage" during an interim period, the agreement permits Bonneville to defer the majority of the site restoration for 20 years, leaving the sites and the structures available for potential reuse that would reduce or eliminate Bonneville's funding obligation. The total cost of the level of remediation under the agreement is currently estimated at $45 million.

To meet its proposed financial commitment for remediation, Bonneville placed funds in a separate interest-bearing trust account in order to have sufficient funds for the eventual final remediation. Bonneville's site remediation obligation, if reuse of the sites and structures does not occur, would not be conditioned on the adequacy of funds in the trust account.

Customers and Other Power Contract Parties of Bonneville's Power Business Line

Historically, Bonneville has had power sales and related contracts with four main classes of customers: Preference Customers, DSIs, Regional IOUs and extra-Regional customers. Bonneville also sells relatively small amounts of power to several federal agencies within the Region. The revenues derived from these customers provide Bonneville with a large portion of the funds needed to pay its costs. For information regarding the relative amounts of customer revenue and other information, see the table entitled "Federal System Statement of Revenues and Expenses" under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data." Bonneville also earns revenues from the provision of transmission service to the foregoing and other customers. See "TRANSMISSION BUSINESS LINE—Bonneville's Transmission System."

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. In addition, 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 which relate to other market participants which have a direct or indirect relationship with such counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, 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.

Preference Customers

Preference Customers, which consist of qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, are entitled to a statutory preference and priority ("Public Preference") in the purchase of available Federal System power. These customers are eligible to purchase power at Bonneville's favorable "Priority Firm Rate" (or, "PF Rate") for most of their loads, and as a class are Bonneville's principal customer base. 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 entity for the same power. In the opinion of Bonneville's General Counsel, the 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 entity.

Direct Service Industrial Customers

Bonneville may, but is not required to, offer to sell power to a limited number of DSIs within the Region for the purchase of power for their direct consumption. For several years prior to 1995, Bonneville's annual DSI firm loads averaged approximately 2800 average megawatts. Through the implementation of the Subscription Strategy, Bonneville signed contracts with eight DSI companies to serve about 1500 average megawatts of loads for the five years beginning October 1, 2001; however, the amount of power now being purchased by the DSIs is substantially less than the initially contracted amount. See "Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—DSI Loads."

Regional Investor-Owned Utilities

As part of Bonneville's Subscription Strategy, Bonneville entered into certain agreements, as amended, with all six of the Regional IOUs in settlement of Bonneville's statutory obligation to provide benefits under the Residential Exchange Program for specified periods beginning October 1, 2001. See "—Certain Statutes and Other Matters

Affecting Bonneville's Power Business Line—Residential Exchange Program," "—Power Marketing in the Period After Fiscal Year 2001," "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data," "—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates" and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Bonneville provides firm power to the Regional IOUs under contracts other than long-term firm requirements power sales contracts. Bonneville also sells substantial amounts of peaking capacity to Regional IOUs.

Exports of Surplus Power to the Pacific Southwest

Bonneville sells and exchanges power via the Pacific Northwest-Pacific Southwest Intertie (the "Southern Intertie") transmission lines to Pacific Southwest utilities, power marketers and other entities, which use most of such power to serve California loads. These sales and exchanges are composed of firm power and non-firm energy 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 Northwest customer's request if the proposed export sale is at a higher FERC-approved rate than the Northwest 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.

In 1995, in view of the Regional load diversification away from Bonneville that was then occurring, Congress enacted a law that authorized Bonneville to sell for export out of the Region a limited amount of power unencumbered to a degree by the Regional Preference recall rights. Bonneville entered into a number of such excess federal power contracts that have remaining terms requiring Bonneville to export power after October 1, 2001. Bonneville does not expect to have substantial new amounts of such excess federal power to sell during the five-year rate period beginning October 1, 2001.

Pacific Southwest utilities typically account for the greatest share of purchases of seasonal surplus energy from Bonneville and these sales account for the greatest share of revenues from Bonneville's exports. The amount of seasonal surplus energy that Bonneville has available to export depends on precipitation and other power supply factors in the Northwest, the available transmission capacity of the Southern Intertie, the attributes of restructured power markets in the Pacific Southwest and other factors that may constrain exports notwithstanding the availability of power.

While Bonneville designs its power rates, including its rates for out-of-Region power sales, to recover its costs, it does so with flexible price levels that enable Bonneville to make additional sales in a competitive marketplace. Revenues that Bonneville obtains from exporting power out of the Region depend on market conditions and the resulting prices. These revenues are affected by the weather and other factors that affect demand in the Pacific Southwest and the cost and availability of alternatives to Bonneville's power. The cost of alternative power 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 sold to the Pacific Southwest. Such sales may be limited, however, by Southern Intertie capacity and other factors.

Effect on Bonneville of Developments In California Power Markets

California power markets experienced historically high power prices and volatility in the period 1999-2001. For much of that period, the California investor-owned utilities (the "Cal-IOUs"), were faced with having a cap on the rates that they could charge their customers while being required to purchase virtually all of their power requirements at prices that were multiples of the rates they could charge.

The weakened financial positions of the Cal-IOUs, particularly Pacific Gas & Electric ("PG&E"), which filed for protection under federal bankruptcy laws in April 2001, and Southern California Edison ("SCE"), also affected the financial condition of two entities with central roles in the restructuring of California's electric power industry. One such entity is the California Independent System Operator ("Cal-ISO"), a nonprofit entity that operates, but does not own, most transmission in the state and is responsible for assuring reliable transmission to the Cal-IOUs and others. By far the largest users of the Cal-ISO's services and hence the largest revenue sources for the Cal-ISO were the Cal-IOUs. Defaults by PG&E and SCE in payments for energy and transmission resulted in concerns by energy suppliers that the Cal-ISO was not a creditworthy supplier, and led to the intervention by the State of California as purchaser of electric power to supply consumers served by the Cal-IOUs. In July 2003, PG&E Energy Trading – Power L.P. ("PGET"), a power marketing affiliate of PG&E and an energy trading counterparty of Bonneville's, also filed for bankruptcy protection. See "BONNEVILLE LITIGATION—PGET Bankruptcy."

The second such entity is the nonprofit California Power Exchange ("Cal-PX"), which suspended operations on January 31, 2001 but was theretofore responsible for operating a day-ahead power exchange through which the Cal-IOUs were obligated to purchase virtually all of their power requirements. As a consequence of the continued operation of the exchange during periods of unprecedented high market prices when the Cal-IOUs' retail rates could not recover the market prices for power, the Cal-PX has substantial outstanding payment obligations due from the Cal-IOUs. The Cal-PX filed for bankruptcy protection in March 2001.

Bonneville entered into certain power sales through the Cal-PX for which Bonneville is due payment but has not yet been paid. Bonneville ceased selling into the Cal-PX in December 2000. In addition, through January 10, 2001, Bonneville sold power and related service to the Cal-ISO to help it maintain transmission reliability in California. The Cal-ISO has outstanding payment obligations to Bonneville for such purchases. Bonneville also has a long-term seasonal power exchange agreement with SCE. Bonneville estimates that its total exposure for sales and exchanges with the foregoing California parties arising since October 1, 2000, is about $84 million. Based on its current evaluation, Bonneville recorded provisions for uncollectible amounts, which in management's best estimate are sufficient to cover any potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

In connection with the historically high power prices and volatility in West Coast power markets, FERC initiated three proceedings to address, under the Federal Power Act, whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. Bonneville is participating in the three proceedings.

In the first proceeding (the "California Refund Docket"), FERC reviewed the extent to which the prices of power sales through the Cal-PX and to the Cal-ISO were "unjust and unreasonable" in the period October 2, 2000 to June 19, 2001. FERC concluded that unjust and unreasonable pricing in fact occurred during that period. Subsequently, FERC appointed an administrative law judge to determine a pricing structure that approximates a competitive market and to determine the amount of refund liability of various power sellers that participated in such sales. Bonneville was a net seller through the Cal-PX and to the Cal-ISO during the period at issue.

In December 2002, the judge issued certain Proposed Findings that indicate the possible range of refund liability in the California Refund Docket. The Proposed Findings are subject to review by FERC. In March 2003, FERC issued an order in the California Refund Docket increasing the potential refund liability of participants, including Bonneville, to the proceeding. The increase is due to the substitution of producing area natural gas prices in place of the California gas index prices previously used in the calculation. Bonneville estimates that this could increase Bonneville's refund exposure, although the actual refund exposure to Bonneville remains uncertain. On June 25, 2003, FERC issued a ruling requiring participants (including Bonneville) in the California Refund Docket to justify their bids into the Cal-ISO and Cal-PX if such bids exceeded $250 per megawatt hour for the period January 2000 to June 2001. In view of the foregoing developments in the California Refund Docket, Bonneville expects that its aggregate refund exposure will be less than the amount owed to Bonneville by the Cal-ISO and Cal-PX and that such amounts will be netted. Nevertheless, Bonneville cannot assure that its refund exposure, if any, would be netted against amounts owed to it by the Cal-ISO and Cal-PX.

In a second proceeding (the "Northwest Spot Market Docket"), FERC reviewed the extent to which the pricing of power sales in the bilateral "spot market" in the Pacific Northwest was "unjust and unreasonable" in the period December 25, 2000 through June 19, 2001.

In calendar year 2001, a FERC-appointed administrative law judge for the Northwest Spot Market Docket made recommendations to FERC concluding, among other things, that the prices charged in the bilateral "spot market" in the Pacific Northwest during the relevant period were not unjust and unreasonable, that refunds should not be ordered, and that FERC should conduct no further hearings and should terminate the proceeding. In addition, the judge found that the reasoning that underlies the assertion of FERC's refund authority over power sales from Bonneville and other non-jurisdictional utilities to the Cal-ISO and through the Cal-PX markets in the first proceeding does not apply to bilateral power sales of such utilities in the Pacific Northwest. Parties filed petitions for rehearing and FERC issued an order on November 11, 2003 denying the petitions and affirming the judge's recommendations. Appeals challenging the order have been filed in the Ninth Circuit Court.

While Bonneville was a participant in the two foregoing refund proceedings, Bonneville took the position before FERC in certain petitions for rehearing that FERC has no jurisdiction over Bonneville in this matter under the Federal Power Act, and therefore that FERC may not assess refund liability against Bonneville. Several other non-jurisdictional utilities have also filed petitions for rehearing challenging FERC's assertion of jurisdiction over them in this matter. On December 19, 2001, FERC rejected Bonneville's and the other non-jurisdictional utilities' petitions. Several non-jurisdictional utilities, including Bonneville, have filed appeals in Federal appellate court.

In the third related proceeding (the "Show Cause Proceeding"), FERC announced in February 2002, that it was investigating whether any entity, including Bonneville, manipulated short-term electric power and natural gas prices in the West or otherwise exercised undue influence over wholesale prices in the West, from the period January 1, 2000 forward.

On June 25, 2003, FERC issued Show Cause Orders to over 60 Identified Entities in the Cal-ISO and Cal-PX markets. The Show Cause Orders require such entities to show why certain market activities did not constitute gaming practices. Bonneville was named as an Identified Entity. After entering into discussions with Bonneville over the allegations contained in the Show Cause Order, FERC staff has moved FERC to dismiss the matter against Bonneville. On January 22, 2004, FERC upheld the dismissal of the Show Cause order issued on June 25, 2003. Certain parties have filed for rehearing of the matter.

Certain Statutes and Other Matters Affecting Bonneville's Power Business Line

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 does not have a statutory obligation to meet all firm loads within the Region or to enter into contracts to sell any power directly to a DSI after fiscal year 2001.

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. 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 (1) the capability of the utility's firm peaking capacity and energy resources used in operating year 1979 to serve its own loads; and (2) 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 and all of its Regional IOU customers have generating resources, which they may use to meet their firm loads in the Region. Under requirements power sales contracts that expired in fiscal year 2001, each of these customers had to identify annually 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 also included in all Subscription Agreements under which Bonneville has a load following obligation. In connection with its Subscription Strategy, Bonneville tendered proposed requirements power sales contracts to each of the Regional IOUs for specified periods following the expiration of the IOUs' requirements contracts at the end of fiscal year 2001. All of the Regional IOUs elected not to execute such agreements.

As required by law, Bonneville's power sales contracts with Regional utilities also include provisions that enable Bonneville, after giving notice, to allocate Federal System power, in accordance with statutory provisions, among its customers if Bonneville determines that it will have insufficient power, on a planning basis, to meet its firm load obligation. Bonneville does not anticipate experiencing a shortage of firm power that would require an allocation pursuant to these provisions. Bonneville's Subscription Strategy helped define Bonneville's power-marketing program for the ten years beginning October 1, 2001 and intended to extend the benefits of low-cost Federal System power widely throughout the Region. Among other things, the Subscription Strategy is intended to assure that Bonneville meets its statutory load obligations in the Region and avoids a resource planning insufficiency that would lead Bonneville to propose an allocation of Federal System power among its Regional customers. See "—Power Marketing in the Period After Fiscal Year 2001."

Although Bonneville has contracts to sell firm power to extra-Regional customers, Bonneville is not required by law to offer contracts to meet these customers' firm loads. Similarly, Bonneville provides firm power to certain federal agencies within the Region; however, Bonneville is not required by law to offer to meet these agencies' firm loads.

<u>Federal System Load/Resource Balance</u>. 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.

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 in the Subscription contract and power rate development process; (ii) the amount of Augmentation Purchases that Bonneville will have to make to meet Subscription loads; (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions; (iv) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional loads; (v) changes in the regulation of power markets at the wholesale and retail level; and (vi) the overall load growth from population changes and economic activity within the Region.

Bonneville had estimated that its loads for the five years beginning October 1, 2001 (pre-existing obligations during such period plus anticipated Subscription loads) could exceed Federal System generation resources. Bonneville made power purchases in the market to address a portion of this potential shortfall, however, prices soared in the highly volatile deregulated wholesale power market. At the higher prices, Bonneville could not meet all obligations and maintain the initial base rate levels proposed in the Subscription process. To address the volatility of the wholesale power market, Bonneville negotiated amendments to certain Subscription contracts and proposed related rates, which incorporate: (1) cost recovery measures tied to the wholesale market price for power purchased by Bonneville to meet Subscription loads; and (2) reductions in Bonneville's power sales obligations through a combination of contracted load reductions and energy conservation measures. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE FINANCIAL CONDITION." There are a number of variables that will affect the exact amount of load Bonneville will be required to serve during the five years beginning October 1, 2001. Customers have limited contract rights to withdraw from the Subscription contracts. See "—Power Marketing in the Period After Fiscal Year 2001." In addition, the contracted load reductions have various terms, but in no case do they extend past the end of fiscal year 2006. Thereafter, it is uncertain how much of that load will revert back to Bonneville. Among other things, the price of alternative power, load growth, and aluminum prices could affect Bonneville's power sales obligations, particularly in the later portion of the five-year rate period.

Bonneville's Authority to Add Resources. In order to meet the foregoing power sales 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: (1) electric power, including the actual or planned electric power capability of generating facilities; or (2) 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 may lead Bonneville to acquire additional power and conservation resources. The extent to which Bonneville does so will depend on the effects of the competitive wholesale electric power market, 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: (1) exchange of surplus Bonneville peaking capacity for firm energy; (2) receipt of additional power from improvements at federally and non-federally owned generating facilities; and (3) 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 Council. The governors of the states of Washington, Oregon, Montana and Idaho each appoint two members to the Council. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations.

Bonneville's Resource Strategies. Increased competition, deregulation in the electric power market and loss of hydropower flexibility due to Endangered Species Act ("ESA") constraints have major implications for Bonneville's resource acquisition strategy. Given uncertainties over the amount of loads that Bonneville will be required to meet in the long term, any resource investment that involves irrevocable, high fixed costs over a period longer than Bonneville's contracted load obligation is much riskier than it would have been in the past. Bonneville has indicated to Regional interests that Bonneville would prefer in the future to avoid assuming the responsibility of meeting incremental Regional power loads above the generating capability of the existing generating resources of the Federal System. Bonneville has also indicated that it would consider using tiered power rates under which the anticipated higher cost of electric power from new power purchases to meet such incremental loads would be recovered from customers to the extent they place incremental load obligations on Bonneville. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Marketing After Fiscal Year 2006."

Should Bonneville assume incremental load obligations above the existing generating resources of the Federal System, Bonneville believes that, in general, new resources 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. Therefore, Bonneville's current resource strategy, in general, is to acquire resources that can accommodate yearly fluctuations in Bonneville loads and that add flexibility to the system.

Short-term (less than five year) purchases are the only type of resource that meets this resource acquisition strategy. Short-term purchases almost always will fit these conditions better than other resources, including long-term combustion turbine resources, because purchases generally do not involve incurring high, 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 dry years when there is comparatively little hydroelectric power available. Since Bonneville's resources are predominantly hydro-based while most other West Coast producers are 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 dry 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 loads for which Bonneville had not previously purchased power. In wet years, purchase requirements can be significantly reduced as Bonneville would meet more of its load with non-firm hydroelectric power.

By contrast to a reliance on long-term resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville will 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's short-term resource purchase strategy is complemented by two other opportunities. First, Bonneville seeks to acquire power from renewable resources. The bulk of such purchases is likely to be from wind generation because of the increasing cost-effectiveness of wind generation projects and due to the expectation that the new wind generation projects can become operational within 12-18 months of a decision to proceed. The amount of wind energy resources that Bonneville ultimately acquires is uncertain and will depend on its future long-term Regional load obligations and the outcome of studies in progress that will assess, among other things, the impact of such an intermittent resource on power system operations. If there is a significant adverse impact, then wind purchases may be limited to a far lesser amount. With regard to renewable resources, Bonneville presently purchases a total of approximately 14.5 average megawatts from three wind energy projects in Wyoming, 20 average megawatts from two wind energy projects in central Oregon, and 30 average megawatts from a wind energy project on the eastern portion of the border between Oregon and Washington, 15 kilowatts from a solar photovoltaic project in southern Oregon, and 38 kilowatts from a solar photovoltaic project located on the Hanford Nuclear Reservation in Washington. These facilities are in operation. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project under construction in northern California. The geothermal project was originally scheduled to become operational in December 2005 but construction is behind schedule. Bonneville's power purchase contract with the geothermal developer contains provisions allowing Bonneville to terminate if certain deadlines are not achieved and it is possible that Bonneville may seek to terminate the agreement.

As a second short-term resource strategy, Bonneville encourages electric power conservation measures. Bonneville provides a 0.5 mills per kilowatt-hour rate discount to those of its customers that implement conservation measures and/or renewable resource projects. In addition, Bonneville is purchasing about 100 average megawatts of electric power conservation through fiscal year 2006 as part of its conservation-augmentation strategy. Any such resource development should lessen Bonneville's reliance on spot market power purchases.

Bonneville believes that this resource strategy over the long-term is stable and is the most cost-effective strategy today given resource lead times, product demand uncertainty, and hydro system variability. In addition, the duration of Bonneville's recently executed Subscription power sales agreements, which have terms of five and ten years, means that Bonneville is not necessarily assured that it will have long-term committed loads to support higher incremental cost, long-term capital investments in resources having expected useful lives of 15 to 20 years or more. Relying on short-term purchases for the time being does not necessarily preclude other resource acquisitions, if needed, sometime in the future.

Under the Subscription Strategy, Bonneville substantially increased its contracted load obligation, which has led Bonneville to make Augmentation Purchases. Consistent with the foregoing resource strategy, Bonneville is relying primarily on short-term (five years or less) purchase agreements to meld with firm power and seasonal surplus energy from the Federal System to meet these additional firm loads. See "—Power Marketing in the Period After Fiscal Year 2001." While Bonneville believes that existing Augmentation Purchases and other actions to date will be sufficient to meet its loads through fiscal year 2006, it is possible that it may have to make additional power purchases if loads are substantially higher than expected or if the amount of power provided by Federal System generating resources or existing power purchases decline unexpectedly.

Residential Exchange Program

The Northwest Power Act created the Residential Exchange Program to extend the benefits of low-cost federal power to all residential and small farm power users in the Region. In effect, the program has resulted in cash payments by Bonneville to exchanging utilities, who are required to pass the benefit of the cash payments through in their entirety to eligible residential and small farm customers.

Under the Residential Exchange Program, Bonneville "purchases power" offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology limiting the costs that may be included in an exchanging utility's average system cost to the production and transmission costs that an exchanging utility incurs for power. Bonneville then offers 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 — Bonneville makes cash payments to the exchanging utility in an amount determined by multiplying the exchanging utility's eligible residential load times the difference between the exchanging utility's average system cost and Bonneville's applicable PF rate, if such PF rate is lower. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates." The net costs of the Residential Exchange Program are shown in the Federal System Statement of Revenues and Expenses set forth under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data."

As part of the Subscription Strategy, Bonneville signed agreements with the Regional IOUs to settle Bonneville's Residential Exchange obligation for the period July 1, 2001 through September 30, 2011. These agreements provide for both sales of power and cash payments to the Regional IOUs. Bonneville's settlement of its Residential Exchange obligations was later challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

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 federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program (the "Council 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 conformance with the ESA and certain biological opinions prepared by the National Oceanographic and Atmospheric Administration—Fisheries ("NOAA Fisheries," which is a part of the U.S. Department of Commerce and which was formerly known as National Marine Fisheries Service) and the U.S. Department of Interior acting through the U.S. Fish and Wildlife Service ("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 the Bureau that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the federal projects' power purpose (as opposed to other project purposes such as irrigation, navigation and flood control). These measures mitigate for the impact on fish and wildlife of the construction and operation of hydroelectric dams of the Federal System.

Bonneville also implements and funds measures proposed in the Council Program, which the Council periodically amends. The Council Program calls for a variety of mitigation measures from habitat protection to mainstem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and force 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 measures funded by Bonneville. While many of the measures in the Council's Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's 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," both of which are driven primarily by ESA requirements. Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing the Council Program, and which include expense and capital components for ESA–related and some non-ESA-related measures that are located at sites away from the Federal System dams; (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps, Bureau and Bonneville; and, (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for the Lower Snake River Hatcheries and of the Corps and Bureau for Federal System projects.

"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 hydroelectric system been operated without any fish and wildlife operating constraints. 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 free of fish constraints, 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.

Bonneville estimates that in aggregate, Direct Costs and Replacement Power Purchase Costs were about $439.6 million in fiscal year 2003. In addition, Bonneville estimates that it had about $79.2 million in Foregone Power Revenues. The total of the preceding costs is within the range of such costs assumed by Bonneville in setting the 2002 Final Power Rates.

The Endangered Species Act. As noted above, Bonneville, the Corps and the Bureau are subject to the ESA. To a great extent, compliance with the ESA determines how the Federal System is operated for fish and dominates most fish and wildlife planning and activities. The listings have resulted in major changes in the operation of the Federal System hydroelectric projects and a substantial loss of flexibility to operate the Federal System for power generation. Apart from changes in Federal System operations that adversely affect power generation, compliance with the ESA has also resulted in additional Federal System costs in the form of non-operational measures funded from Bonneville revenues.

Among other things, the ESA requires that federal agencies such as Bonneville, the Corps and the Bureau, take no action that would jeopardize the continued existence of listed species or result in the destruction or adverse modification of their critical habitat. Since 1991, there have been listed as threatened or endangered under the ESA 12 species of anadromous fish (salmon and steelhead) that are affected by operation of the Federal System. 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 is now operated for power production 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 the listed species. The biological opinions provide information that Bonneville, the Corps and the Bureau can use to ensure that their actions with respect to the operation of the Federal System satisfy the ESA. By acting consistently with the biological opinions, Bonneville, the Corps and the Bureau generally demonstrate that jeopardy to listed species is being avoided. Specifically, Bonneville, the Corps and the Bureau have chosen to implement certain specified measures recommended in the biological opinions as being necessary to avoid jeopardy. The adequacy of the biological opinions and their implementation are subject to, and have been subjected to, judicial review.

Operation of the Federal System consistent with the biological opinions has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise be run through turbines to generate electricity may be spilled to aid in downstream fish migration without producing electric energy. 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 changes, under certain water conditions, Bonneville has had to, and may have to, purchase additional energy for the fall and winter to meet load commitments than would otherwise have been met with the hydroelectric system. In addition, the flow changes have meant that Bonneville has had comparatively more surplus energy to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System in conformance with the biological opinions and the Council Program, as in effect as of the beginning of fiscal year 2000, decreased Federal System generation capability by about 1000 average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the first biological opinion in 1995. The consequences of this decrement in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

While in calendar years 1999-2001 the seasonal variance in market prices of electric power was substantially less pronounced, historically, power prices in the Northwest have been much higher in the winter because of higher regional heating requirements and lower in the spring and summer as those requirements abated. Thus, flows in aid of fish have resulted in a reduction in the amount of power generally, and reduced the amount of power in high winter load portions of the year when power has typically had greater economic value.

These ESA listings and related actions to protect listed species and their habitat have also resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville fish costs increased from about $20 million in fiscal year 1981 to $150 million in fiscal year 1991. After the issuance of the first biological opinion affecting Federal System operations, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts rose to $399 million in 1995. As noted above, Bonneville estimates that the total of Direct Costs and Operational Impacts in fiscal year 2003 was about $518.8 million.

2000 Biological Opinion. In December 2000, NOAA Fisheries promulgated a new biological opinion ("2000 Biological Opinion") that superseded all previous opinions issued by it concerning the Federal System hydroelectric dams. The 2000 Biological Opinion has been coordinated with a Fish and Wildlife Service biological opinion issued in 2000 relating to certain other species and they are intended to be mutually consistent. The 2000 Biological Opinion includes a number of measures that will affect Federal System operations and dam configurations in order to improve anadromous fish passage survival through the hydro system. In addition, the 2000 Biological Opinion calls for other measures from increased spill and additional flow requirements to extensive Columbia River Basin-wide habitat protections and enhancement efforts and fish hatchery reforms.

Included among the 13 biological opinion alternatives around which Bonneville developed its 2002 Final Power Rates were several that would have called for breaching four Federal System Snake River dams. The direct cost of breaching the dams would be very high. In addition, the loss of the generation from the dams would substantially affect the power generation capability of the Federal System, reducing current expected output by approximately 1200 average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales. The 2000 Biological Opinion does not recommend implementation of dam breaching. However, NOAA Fisheries indicates that if measurable improvements in survival of listed fish are not seen, it may reinitiate formal consultations under the ESA with Bonneville, the Corps and the Bureau and recommend that they pursue authority to breach the four dams. In the opinion of the General Counsel to Bonneville, Congress would be required to enact legislation authorizing breaching of the dams.

The 2000 Biological Opinion sets forth a series of checkpoints to test the efficacy of programs identified therein to aid listed fish species. The 2000 Biological Opinion anticipates full implementation by 2010. The 2000 Biological Opinion includes provisions for NOAA Fisheries to issue evaluations near the end of each of calendar years 2003, 2005 and 2008, documenting whether the reasonable and prudent alternative measures identified in or to be developed under the 2000 Biological Opinion are on track or meet expectations. The evaluations are required to grade whether the measures are (a) failing, (b) acceptable, or (c) between failing and acceptable, with respect to (i) whether rolling one- and five-year plans for program implementation are on track, (ii) whether hydro performance (measures to improve fish passage past dams) and offsite mitigation (improvement of hatcheries, habitat and fish harvest) measures are on track, and (iii) whether the population status of listed species is on track.

In December 2003, NOAA responded to the 2003 checkpoint with a "between failing and acceptable" rating. Under the 2000 Biological Opinion, NOAA Fisheries indicated that the 2008 checkpoint in particular is expected to focus on performance more than under the earlier checkpoints. The 2000 Biological Opinion provides that if NOAA Fisheries concludes that there is a failure in these respects it will recommend whether to continue with the reasonable and prudent alternatives described in the 2000 Biological Opinion, revise them and/or recommend that the dam operators seek new legal authority from Congress. The new authority to be sought could include authority to breach dams, among other authorities. If such authority were not forthcoming, NOAA Fisheries indicates that it would then seek to reinitiate consultation pursuant to the ESA with the Corps and the Bureau and Bonneville over their hydroelectric project operations and recommend a new reasonable and prudent alternative for avoiding jeopardy to listed species.

A number of interests have filed litigation in connection with the 2000 Biological Opinion. In May 2003, the United States District Court for the District of Oregon ruled that the 2000 Biological Opinion is inadequate because it relies on offsite mitigation measures that are "not reasonably certain to occur." In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. The court's order gives NOAA Fisheries until early June 2004 to reconsider the biological opinion. To address the court's concerns, it is possible that a revised biological opinion may increase the forms and extent of mitigation measures beyond those required in the 2000 Biological Opinion as reviewed by the court. If NOAA Fisheries were to include additional or expanded measures in a new or amended biological opinion it is possible that substantial additional costs could be borne by Bonneville. In an additional ruling in late June 2003, the court agreed to permit the 2000 Biological Opinion to remain in effect on an interim basis for up to one year while the 2000 Biological Opinion is on remand to NOAA Fisheries. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville. In 1995, the United States Treasury, the Office of Management and Budget, 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 allows Bonneville to exercise its Northwest Power Act authorities to implement fish and wildlife mitigation on behalf of all of a project's Congressionally authorized purposes, such as irrigation, navigation, power and flood control, then recoup (*i.e.*, take a credit for) the portion allocated to non-power purposes. The agreement also directs Bonneville to recoup certain Direct Costs and Replacement Power Purchase Costs. The amount of such recoupments was about $354 million, $38.4 million and $97.3 million in fiscal years 2001, 2002 and 2003, respectively. These credits are treated as revenues in Bonneville's ratemaking process, and such recoupments are taken against Bonneville's lowest priority financial obligation, its payments to the United States Treasury. The recoupments are initially taken based on estimates and are subsequently modified to reflect actual data. Two important costs that may be recouped under section 4(h)(10)(C) are the cost of foregone power revenues and replacement power purchases arising from certain hydroelectric system operations for the benefit of fish and wildlife. Both of these categories of costs can occur to a greater degree in dry years when, historically, market prices for power are comparatively high. Thus, Bonneville believes that the amount of 4(h)(10)(C) recoupments will tend to be greater in dry years when power prices tend to be high and Bonneville has less power to market, and therefore tends to have lower power revenues.

In addition to agreeing to a protocol for the foregoing, annually realized 4(h)(10)(C) recoupments, the same federal agencies also agreed in 1996 to establish a "Contingency Fund" to offset extraordinary revenue impacts from operations were there to occur certain adverse court rulings relating to biological opinions, specified poor water conditions and costs resulting from natural disasters or fishery emergencies. The source of the Contingency Fund is amounts Bonneville had theretofore expended for the non-power portion of fish and wildlife costs but had not recouped under section 4(h)(10)(C) against its payments to the United States Treasury. In 1997, Bonneville certified that there were approximately $325 million in costs for past mitigation that had not been recouped against its payments to the United States Treasury. Bonneville obtained access to the Contingency Fund for the first time at the end of fiscal year 2001 in view of the poor water conditions that year, and applied about $247 million from the Contingency Fund to reduce its fiscal year 2001 payments to the United States Treasury, leaving an unused balance of about $78 million in the Contingency Fund. The conditions governing access to the Contingency Fund were not met in fiscal year 2002 but poor water conditions in fiscal year 2003 provided access to the Contingency Fund and

Bonneville applied the remaining credits in the fund to its United States Treasury payment in fiscal year 2003. Thus, the Contingency Fund is fully and finally depleted.

Council's Fish and Wildlife Program. In November 2002, the Council adopted a new Fish and Wildlife Program (the "2002 Program"). The 2002 Program focuses on an ecosystem approach to rebuilding fish and wildlife populations in the Columbia River Basin, consistent with the 2000 Biological Opinion. Estimated costs to Bonneville of the Council's measures, as then encompassed in amendments to the Council's 1995 Program, were included in Bonneville's assumptions for the 2002 Final Power Rates. The 2002 Program, like the Council's predecessor program, sets forth an "integrated program" budget to Bonneville for both the Council Fish and Wildlife Program and the off-site mitigation program under the 2000 Biological Opinion. The costs of the integrated program (Integrated Program Costs) are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General."

In response to financial developments over the past two years, Bonneville reiterated, and the Council confirmed, an average expense accrual budget level of $139 million per year for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's 2002 Program for fiscal years 2003 through 2006. This level is in the range of projected costs assumed in Bonneville's 2002 Final Power Rates. In June 2003, the Yakama Nation, a tribal entity, filed a petition in the Ninth Circuit Court to request a review of Bonneville's fund levels under the Council's 2002 Program, as well as the Council's support of such funding levels. See "BONNEVILLE LITIGATION—Yakama Nation Litigation."

Bonneville can provide no assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System, including measures resulting from current and future listings under the ESA, current and future biological opinions or amendments thereto, future Council Fish and Wildlife Programs or amendments thereto, or litigation relating to the foregoing.

Power Marketing in the Period After Fiscal Year 2001

General. Under a power marketing approach (the "Subscription Strategy") begun in 1997, Bonneville proposed to subscribe access to Federal System electric power under long-term contracts to its Regional customers for the period after October 1, 2001, which is the date after which virtually all of Bonneville's prior Regional power sales contracts and all of Bonneville's Residential Exchange Program Contracts expired. Under the Subscription Strategy, Bonneville entered into long-term Subscription contracts through which it contracted to sell all of its then available firm power to Regional customers for various terms.

Preference Customer Loads. Under the Subscription Strategy, Bonneville entered into long-term power sales contracts directly or indirectly to provide power to meet loads of about 135 Preference Customers. With the exception of eight contracts, which have terms of five years, such agreements have terms of ten years.

Under the Subscription Strategy, Bonneville sells Preference Customers three basic power products, which are not exclusive of each other: (i) Block Sales under which Bonneville provides ten-year fixed blocks of power at agreed times on a take or pay basis, (ii) Slice of the System, a form of requirements service in which Bonneville sells a proportion of Federal System output (including both firm power and what would otherwise be seasonal surplus energy) in return for a promise of the customer to pay a correlative proportion of the costs of the Federal System, and (iii) Partial and Full Requirements Products under which Bonneville provides partial or full requirements service for all or a portion of a customer's loads. Full requirements customers accept constraints on their ability to shape their purchases from Bonneville for any reason other than following variations in consumer load. Partial requirements service is made available to Preference Customers who request firm power load requirements service but who also want some flexibility to shape their purchases from Bonneville to optimize their own resource operations.

Under the foregoing agreements Bonneville is obligated to provide roughly 6300-6400 average megawatts to meet Preference Customer loads, on average, over the remaining term of the five-year rate period beginning October 1, 2001. Of this amount, about 1600 average megawatts is sold as Slice of the System, about 1900 average megawatts is in the form of Block Sales and the remainder is in the form of Requirements Products. The actual amount of power sold by Bonneville under the Slice of the System contracts varies from year to year depending on actual generation. The 1600 average megawatts figure reflects the firm power component of the Slice of the System. Slice of the System customers also receive what otherwise would be seasonal surplus energy in amounts that depend on precipitation in the Columbia River drainage. A Regional IOU has challenged Bonneville's statutory authority to enter into Slice of the System contracts. See "BONNEVILLE LITIGATION—Pacific Northwest Generating Cooperative v. Bonneville Power Administration."

The exact amount of Bonneville's obligation to Preference Customers is somewhat uncertain and depends on conservation activities, actual demand (which can fluctuate with weather and Regional economic activity), load reduction arrangements and other factors. For example, Bonneville entered into certain agreements with Preference Customers to reduce loads placed on Bonneville in fiscal years 2002 and 2003.

The Slice of the System (or "Slice") contracts require that customers make monthly payments based on expected costs of operating the Federal System, which payments are subject to retroactive annual adjustment to reflect actual costs. The Slice customers have the right to an outside audit of such annual "true up" adjustments. Certain Slice customers requested such an audit of the fiscal year 2002 "true up" adjustment, and retained an accounting firm to conduct an audit and prepare a final report, which was completed on June 13, 2003. The Slice customer audit asserted that the Slice customers' payments for fiscal year 2002 should be adjusted by removing an additional $83 million from Bonneville's charges. Under the Slice contracts, Bonneville and the Slice customers have 60 days to resolve any outstanding issues after the final report is concluded, after which time Bonneville's response to the auditor's report becomes a final action for purposes of judicial review under the Northwest Power Act. In a related action, several Slice customers filed litigation requesting review of Bonneville's accounting with regard to the Slice of the System product charges for fiscal year 2002. See "BONNEVILLE LITIGATION—Benton County Litigation".

Residential Exchange Program Obligations. As part of the Subscription Strategy, Bonneville and the six Regional IOUs participating in the Residential Exchange Program entered into six separate ten-year contracts ("Residential Exchange Settlement Agreements") that settle Bonneville's statutory Residential Exchange Program obligations during such periods. For the five years beginning October 1, 2001, Bonneville originally contracted to satisfy this obligation through (i) direct sales of 1000 average megawatts of firm power at Bonneville's Residential Load Rate ("RL Rate") and a similar rate in the case of a comparatively small Regional IOU, and (ii) cash payments for an exchange value ("Monetary Benefits" as described immediately below) of 900 average megawatts of firm power. The RL Rate is set at a level equivalent to Bonneville's lowest available requirements service rate, the PF Rate. The "Monetary Benefits" are based on the related amount of power multiplied by the difference between a forecast of the market price of power set in Bonneville's rate case and the RL Rate. All power sales and payments by Bonneville under the Residential Exchange Settlement Agreements, as amended, are provided for the benefit of the Regional IOUs' residential and small farm loads in the Region.

Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of contract amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2002. These amendments and arrangements increased the amount of cash payments that Bonneville would make in respect of the Residential Exchange Settlement Agreements and reduced the amount of physical power sales thereunder. As result, the aggregate cash payments to Regional IOUs that Bonneville has made related to the Residential Exchange Settlement Agreements were about $355 million in fiscal year 2002 and $327 million in fiscal year 2003 and, under a variety of assumptions, are projected to be $389 million in fiscal year 2004, $468 million in fiscal year 2005, and $447 million in fiscal year 2006. As a result of the foregoing load reductions, Bonneville reduced its obligation to make physical power sales under the Residential Exchange Settlement Agreements to about 258 average megawatts of power from fiscal year 2002 through fiscal year 2006. This remaining Residential Exchange Settlement Agreement power sale is to a single Regional IOU at the RL Rate, and is subject to the LB-CRAC, FB-CRAC and SN-CRAC rate level adjustments.

The aggregate cash payments to Regional IOUs described above can be broken down into three separate components. The first component reflects payments for Monetary Benefits under the original Residential Exchange Settlement Agreements. Bonneville estimates that it will pay about $132 million in Monetary Benefits per year on average over the five-year rate period. This amount was about $144 million in each of fiscal years 2002 and 2003. The second component reflects payments for load reductions arising from contract amendments. Through contract amendments with two Regional IOUs, Bonneville obtained an aggregate reduction of about 620 average megawatts in the amount of firm power sales Bonneville was to provide throughout the five-year rate period. To obtain these load reductions, Bonneville agreed to pay the two Regional IOUs about $236 million per year in aggregate.

The two Regional IOUs also agreed to provide Bonneville with a discount to the foregoing payments if there is a settlement of certain litigation filed by Preference Customers challenging Bonneville's authority to enter into the Residential Exchange Settlement Agreements. (The litigation has not been settled.) The two Regional IOUs also agreed that Bonneville could defer making a portion of such payments until later years of the rate period. These payments, whether discounted or not, are recovered under the LB-CRAC in the 2002 Final Power Rates.

The third component reflects load reductions achieved by the exercise by three Regional IOUs of certain conversion rights in their Residential Exchange Settlement Agreements. Through the exercise of these rights, Bonneville's obligation to sell about 125 average megawatts of power was converted into obligations to provide cash payments of about $10 million per year in fiscal years 2002 and 2003. Such payments are affected by the operation of the LB-CRAC, FB-CRAC and SN-CRAC and are expected to fluctuate somewhat from year to year in the remaining three years of the rate period. The payments, whether discounted or not are not recovered under the LB-CRAC in the 2002 Final Power Rates.

The foregoing payments to and by Bonneville under the Residential Exchange Settlement Agreements are affected by the application of at least one of the three intra-rate period rate level adjustments included in the 2002 Final Power Rates. For example, the remaining Subscription power sale by Bonneville and the three converted power sales are served under the RL Rate and are therefore subject to the LB-CRAC, FB-CRAC and SN-CRAC. Under certain contract provisions, the payments by Bonneville under the load reduction amendments are reduced when Bonneville employs a rate level adjustment under the SN-CRAC. In addition, since the Monetary Benefits are subject to certain changes by reference to the RL Rate, Bonneville's Monetary Benefits payments are reduced when the RL Rate level is increased under the SN-CRAC. See "—Subscription Power Rates."

In developing the Subscription process, Bonneville expected to meet its Residential Exchange Settlement Agreement obligations in the period after fiscal year 2006 in full through the actual provision of about 2200 average megawatts of electric power to the Regional IOUs. Under contract provisions with the Regional IOUs, Bonneville has the right to determine how much of its fiscal year 2007-2011 obligation under the Residential Exchange Settlement Agreements will be provided in the form of cash payments and how much will be provided in the form of actual power sales. Bonneville must decide by October 1, 2005 how much power it will provide to the Regional IOUs under the Residential Exchange Settlement Agreements after fiscal year 2006. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

<u>DSI Loads</u>. Historically, Bonneville sold substantial amounts of Federal System electric power to DSIs that smelt or fabricate aluminum. In 1981, as directed by the then recently enacted Northwest Power Act, Bonneville entered into 20-year power sales contracts with eligible DSIs. Under the 1981 contracts Bonneville was obligated to sell the aluminum company DSIs up to roughly 3200 average megawatts of power in aggregate. Under certain 1996 replacement agreements, the DSI loads Bonneville was obligated by contract to serve was reduced to roughly 1800 average megawatts through fiscal year 2001.

The United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court") has held that Bonneville no longer has a statutory obligation to sell any power to meet DSI loads. Nonetheless, as part of Bonneville's Subscription program for the post-fiscal year 2001 period, Bonneville entered into five-year take-or-pay power sales contracts with a number of aluminum company DSIs under which agreements such DSIs agreed to purchase approximately 1500 average megawatts. Under these DSI power sales contracts, as amended, the DSIs may curtail purchases but retain the take-or-pay requirements. If a DSI gives Bonneville advance notice that the DSI is unable or unwilling to take its power obligation to operate its facilities, Bonneville remarkets the power and applies the proceeds to offset the related DSI's payment obligation to Bonneville. In the event that re-marketing proceeds are less than the amounts owed Bonneville under the DSI contract, the DSI remains obligated to pay Bonneville the differential. In the event that re-marketing proceeds exceed the amounts due to Bonneville by the DSI, Bonneville retains the excess proceeds as well.

Bonneville's contracted sales obligations to aluminum company DSIs in fiscal year 2004 are about 600 average megawatts but Bonneville is currently delivering such DSIs about 200-300 average megawatts. The remainder of the sales to aluminum company DSIs (i) have been curtailed by contract amendment, (ii) were terminated because they were rejected in bankruptcy proceedings, or (iii) are not being performed by related DSIs pending likely rejection in bankruptcy proceedings. Currently, four aluminum company DSIs are under bankruptcy protection. See "BONNEVILLE LITIGATION—GNA Bankruptcy," "—Kaiser Aluminum Bankruptcy," and "—Longview Aluminum Bankruptcy."

In view of continued low prices for aluminum relative to the costs of production, and in particular the price of electric power under the DSI contracts, it is possible that other aluminum company DSIs may seek protection under the bankruptcy laws and reject their power contracts with Bonneville. Alternatively, such DSIs may fail to perform their take-or-pay purchase obligations entitling Bonneville to claims for breach of contract. In the event that Bonneville's sales prices under such contracts are higher than market prices it is possible that Bonneville would be left with unsecured claims for accrued accounts receivable and, roughly, the amount of power contracted to be sold times the positive difference between the contract prices minus applicable market prices. Under Bonneville's current forecasts of aluminum prices, Bonneville does not expect that aluminum company DSIs have an economic incentive to perform their purchase obligations in any material amount through the term of the contracts. While these possible future events could expose Bonneville to lost mark-to-market value (depending on volatile power prices) and certain other costs, Bonneville's expectation is that aluminum company DSI loads will remain at very low levels through fiscal year 2006.

Subscription Strategy Contracts Opt-Out Provisions. While Bonneville and its customers have entered into the foregoing Subscription contracts, the ultimate amount of electric power load Bonneville is and will become obligated to meet under such contracts during the next five to ten years remains somewhat uncertain because the Subscription contracts have provisions allowing customers to terminate such contracts if either FERC or the Ninth Circuit Court, which reviews FERC actions on Bonneville's rates, subsequently remands Bonneville's base power rates and Bonneville publishes a record of decision that adopts different rates for such period. The customers may not opt out of their contracts solely on the basis that Bonneville has included the cost recovery adjustment clauses in the rate proposal or that the cost recovery adjustment clauses are employed to increase rate levels. The customers who do not opt out after review of the final rate proposal would be committed to purchase as provided in their Subscription contracts. The 2002 Final Power Rates were approved by FERC in July 2003 but are in litigation in the Ninth Circuit Court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

Risk Management. Bonneville believes that its ability to recover power costs during the five-year rate period is and will be a function of several key risks: (i) the level and volatility of market prices for electric power in western North America, which define the revenues Bonneville receives from discretionary sales of energy; (ii) the level of Bonneville's load serving obligation after voluntary load reductions and negotiated power buy-backs; (iii) water conditions in the Columbia River drainage, which determine the amount of power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (iv) 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 energy produced by the Federal System; and (v) operating costs, generally.

Subscription Power Rates. On June 29, 2001, Bonneville filed its proposed 2002 Final Power Rate Proposal with FERC for the five years beginning October 1, 2001. On July 21, 2003 FERC granted final approval of such rates, although they are subject to legal challenge in the Ninth Circuit Court. The 2002 Final Power Rates include base rates applicable to the varying types of Subscription agreements and certain intra-rate period adjustments that increase or decrease power rate levels depending on certain conditions. The base rate levels are between approximately 1.9 cents per kilowatt-hour and 2.30 cents per kilowatt-hour, excluding transmission and depending on type of service. The base rates are at levels similar to those in effect for like service in the immediately preceding rate period. The 2002 Final Power Rates also include three intra-rate period adjustment mechanisms under which Bonneville can increase, and in some instances decrease, power rate levels: a Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), a Financial Based Cost Recovery Adjustment Clause ("FB-CRAC") and a Safety Net Cost Recovery Adjustment Clause ("SN-CRAC").

The LB-CRAC is designed to recover the net cost of system Augmentation Purchases and certain load reduction agreements that is over and above the cost of such purchases that Bonneville forecasted in a rate filing prepared in

July 2000. The LB-CRAC is not designed to recover the cost of replacing reductions in the firm power generating capability included in the baseline estimate of Federal System firm power if any such reductions occur.

The LB-CRAC is based on periodic forecasts of Bonneville's Subscription augmentation and certain related costs for consecutive six-month periods during the five-year rate period. The costs recovered under the LB-CRAC are those identified costs to Bonneville from addressing the increased loads it assumed under its Subscription power sales agreements, and include the costs of certain power purchases and certain load reduction agreements. Thus, the LB-CRAC is revised each six-month period during the rate period to reflect updated forecasts of Subscription Augmentation Purchase and load reduction costs in the next six months. Another adjustment to the amounts recovered under LB-CRAC reflects actual costs of Subscription augmentation in the prior six-month period to the extent that the forecast for such augmentation costs differ from actual costs in such period. The LB-CRAC is based on the costs of certain Subscription Augmentation Purchases and certain load reduction agreements only and is not subject to any other provision limiting the amount of revenues to be derived by Bonneville thereunder.

The FB-CRAC is designed to restore, on a forecasted basis, Bonneville's financial reserves to certain fiscal year-end reserve levels ("Reserve Targets"). A rate level increase under the FB-CRAC is implemented for an entire fiscal year and occurs during a subject fiscal year only if Bonneville's financial forecast made in the third quarter of the prior fiscal year indicates that the accumulated net revenues for the beginning of the subject fiscal year will be below the accumulated net revenue equivalent of the applicable Reserve Target. In fiscal years 2003-2006, the revenues to be derived under an FB-CRAC increase are capped at a maximum of between $90 million and $115 million per fiscal year, depending on the year.

The SN-CRAC is to be implemented to recover costs on a temporary basis if, at any time during the rate period, Bonneville were to (i) forecast a 50% probability or greater of missing a scheduled payment to the United States Treasury or other creditor or (ii) miss a scheduled payment to the United States Treasury or other creditor. A rate level increase under the SN-CRAC occurs independently of any LB-CRAC or FB-CRAC increase then in effect. An SN-CRAC adjustment could alter certain parameters of an FB-CRAC adjustment, including the amount of revenue that can be collected, the duration of rate level adjustments, and the timing of collection of revenues, in each case under the FB-CRAC. Under the 2002 Final Power Rates, Bonneville is to determine the level of the SN-CRAC in a record of decision after a brief formal rate-setting process.

Sales under Slice of the System contracts (about 1600 average megawatts of firm power plus proportionate amounts of Federal System power that would otherwise be seasonal surplus energy) are not subject to the SN-CRAC or the FB-CRAC but are subject to the LB-CRAC. These customers agreed to pay for a fixed portion of Federal System costs under their contracts and their rates are subject to annual adjustment to recover those costs. About 800 average megawatts of loads of certain small Preference Customers under requirements contracts are not subject to any of the three rate level adjustment mechanisms. These Preference Customers received certain contractual rate protections from Bonneville for making early contract commitments to purchase power from Bonneville on a long-term basis. All other Subscription power sales (Block Sales and the sale of Requirements Products) to Preference Customers are subject to all three rate adjustment mechanisms. The 1500 megawatts of Subscription power sales to DSIs are also subject to all three rate adjustments, although Bonneville expects that the DSIs are unlikely to meet their originally contracted aggregate purchase obligations to a substantial degree. The remaining 200-300 megawatts of Subscription power sales under the Residential Exchange Settlement Agreements are subject to the LB-CRAC, FB-CRAC and the SN-CRAC.

For the first six months of the rate period, the LB-CRAC adjustment increased rate levels by 46% of the base rates for the rate period and, coincidentally, the rates for like service in the preceding rate period. The four subsequent semiannual LB-CRAC adjustments were, respectively, about 39%, 32%, 39%, and 21% of base rates. Bonneville expects that the LB-CRAC for the six months beginning April 1, 2004, will be about 25% of base rates. Bonneville expects that the LB-CRAC adjustments will average about 31% of base rates for the remaining two years of the rate period.

The FB-CRAC was not implemented for fiscal year 2002 rates; however, the FB-CRAC was triggered after the third quarter fiscal year 2002 year-end forecast, thus commencing a one-year rate level increase beginning October 1, 2002. The FB-CRAC adjustment in effect for fiscal year 2003 was roughly 11% of base rates for those contracts to which the FB-CRAC applies. The FB-CRAC was triggered again for fiscal year 2004, at roughly 12%

of base rates. In connection with its proposal for an SN-CRAC rate level adjustment, Bonneville has formally proposed to adjust the financial conditions under which the FB-CRAC would trigger. Such changes would assure that the conditions for the proposed SN-CRAC rate level adjustment are not met unless the FB-CRAC conditions have been met.

Taking the cumulative effects of the base rates, the LB-CRAC and the FB-CRAC into account, average Subscription power rate levels for Block Sales and Requirements Products in each six month period to date were roughly: (i) 2.9-3.3 cents per kilowatt-hour in the first six months of the rate period, (ii) 2.7-3.1 cents in the second six months of the rate period, and (iii) 2.8-3.2 cents per kilowatt hour in the third six months of the period, in each case excluding transmission. Beginning April 1, 2003, the cumulative average Subscription power rate levels were about 3.0-3.4 cents per kilowatt-hour, excluding transmission, and for the first six months of fiscal year 2004 the cumulative average Subscription power rate levels are about 3.0-3.4 cents per kilowatt-hour.

In February 2003, Bonneville estimated that there would be approximately a 26 percent probability that it would meet in full its scheduled fiscal year 2003 payments to the United States Treasury, thereby triggering a process to develop an SN-CRAC rate level adjustment proposal. In June 2003, Bonneville issued a final proposal and record of decision for the SN-CRAC rate level adjustment and submitted the proposal and record of decision to FERC for review and approval. In view of improved water conditions in fiscal year 2003, better than previously expected revenues from discretionary power sales, and effects of cost management and financial liquidity actions, the final proposed SN-CRAC rate level increase for fiscal years 2004-2006 is less than the SN-CRAC rate level adjustment Bonneville initially proposed. Bonneville estimates that the final SN-CRAC rate level adjustment would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels in fiscal years 2004-2006 by an average of about 5 percent over fiscal year 2003 levels.

The final SN-CRAC rate level adjustment proposal is a variable contingent mechanism where the calculation of the actual rate level adjustment for a fiscal year would be made about two months before the beginning of such fiscal year. The adjustment would be based on then current forecasts of the Power Business Line accumulated net revenues for the fiscal year preceding the fiscal year in which the rate level adjustment is to be in effect. Thus, the first year (fiscal year 2004) rate level adjustment under the final SN-CRAC rate level adjustment proposal was determined (on a contingent basis pending FERC approval of the SN-CRAC rate level adjustment) in August 2003 on the basis of then available financial forecasts of fiscal year end 2003 accumulated net revenues. Under that determination Bonneville's SN-CRAC rate level adjustment for fiscal year 2004 would have the effect (after taking into account anticipated FB-CRAC and LB-CRAC adjustments) of increasing Bonneville's overall power rate levels in fiscal years 2004-2006 by an average of about 2.2 percent over fiscal year 2003 levels. This is less than Bonneville forecasted when it submitted the final SN-CRAC rate level adjustment to FERC in June 2003.

In developing the proposed SN-CRAC rate level adjustment Bonneville estimated that the adjustment would assure that Bonneville has an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time in the three fiscal years beginning October 1, 2003. Such estimates are based on a number of forecasts that may not be realized and a number of assumptions that may prove erroneous. Notwithstanding the SN-CRAC rate level adjustment proposed by Bonneville, Bonneville has reserved the ability to develop an additional SN-CRAC rate level adjustment should the conditions of the Final 2002 Power Rate Proposal be met: if at any time during the five year rate period, Bonneville (i) forecasts a 50 percent or greater probability of missing a payment to the United States Treasury or other creditor in the then current fiscal year or (ii) misses a scheduled payment to the United States Treasury or other creditor. Whether and the extent to which Bonneville would increase rate levels under an additional SN-CRAC adjustment would be determined in view of all facts and circumstances at the time.

Assuming the expected effects of the final SN-CRAC rate level adjustment proposal and expected rate level adjustments under the FB-CRAC and LB-CRAC, Bonneville's average power rates for fiscal years 2004-2006 would exceed by more than 50 percent the rate levels in effect for like service in fiscal year 2001, the year preceding the current power rate period. As described herein, the rate level increases under the rate adjustment mechanisms vary depending on the type of Subscription power sales contract. Some contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms.

Rates for Surplus Power. With regard to rates for surplus firm power, Bonneville continues to employ flexible rates that recover Bonneville's cost of providing such power, but at rates that enable Bonneville to participate in power markets. The amount of surplus power that Bonneville will market at such rates will depend on generation and load conditions that vary with weather, streamflows, market conditions and numerous other factors. Rates for the sale of surplus power are not subject to the rate adjustment mechanisms applicable to Subscription power sales.

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, *i.e.,* "stranded." Stranded costs may arise where power customers are able, pursuant to new 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 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 function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. See "—Power Marketing Plan for the Period After Fiscal Year 2001." 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 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 section 211/212 of the Federal Power Act. For a discussion of Order 888 and sections 211/212 of the Federal Power Act, as amended by EPA-1992, see "TRANSMISSION BUSINESS LINE—Nondiscriminatory Transmission Access and Separation of Business Lines."

Bonneville's rates for any FERC-ordered transmission service pursuant to section 211/212 of the Federal Power Act 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 section 211/212.

Shortly after the issuance of Order 888, Bonneville requested clarification of the application of FERC's stranded cost rule to Bonneville in the context of a section 211/212 order for transmission service. 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 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 section 211/212. 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. For a discussion of the proposed formation of a regional transmission organization that could affect some of Bonneville's transmission operation functions see "TRANSMISSION BUSINESS LINE—Bonneville's Participation in a Regional Transmission Organization."

Changes in the Regulation of Regional Retail Power Markets

Since the 1990's, many states and the Federal government have examined possible regulatory changes in retail electric power markets. In general, these proposals would allow end-use electricity consumers to choose their energy suppliers and to purchase power at market prices. This approach contrasts with the formerly predominant regulatory approach, where electric utilities have legal or de facto exclusive retail service territories. In general, the utilities are under an obligation to provide service to consumers located in the utilities' respective service areas. The utilities receive regulated rates of return in the case of profit-making utilities, or are required to sell their power at rates that are cost-based in the case of public agency or cooperatively owned utilities. As under wholesale competitive power markets, the core issue in establishing retail choice is assuring that facilities for transmitting electric power, at the distribution level, be available to all market participants in a manner that does not discriminate in favor of power sales by the owner of such facilities.

Bonneville is limited in its legal authority to sell power directly to end-use consumers, other than to state and Federal agencies and specified DSIs. Accordingly, Bonneville expects to continue to sell the majority of its electric power on a wholesale basis to electric utilities who resell to retail loads. The advent of competition in retail power markets could affect the manner in which Bonneville markets power and the ability of its wholesale customers, in particular its Preference Customers, to maintain the electric power loads they now rely on Bonneville to meet. In such a scenario, Bonneville may be forced to market more of its power to non-utility marketers or load aggregators for resale to end-users. Depending on the terms of any retail access legislation, the reliability of revenues Preference Customers now have from electric power consumers could be diminished. Under some retail access approaches, utilities would have a reduced ability to recover power costs in reliance on their exclusive ownership of distribution facilities for retail service to their end users.

TRANSMISSION BUSINESS LINE

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately- and publicly-owned utilities, power marketers, power generators and others. Bonneville's revenues from the sale of transmission and related services accounted for roughly 15 percent of Bonneville's overall revenues in fiscal year 2003.

Bonneville's Transmission Business Line provides transmission service under FERC's pro forma Open Access Transmission 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 or non-Federal power. Much of Bonneville's transmission service is provided to deliver Bonneville's power sales obligations to its Preference Customers, many of whom take Network Integration service. Point-to-Point service is taken typically by marketers, independent power producers and customers that own or purchase the output of remote generating resources which must be delivered to their service territories. Finally, Bonneville, as an owner of the northern portions of the Pacific Northwest-Pacific Southwest Intertie ("Intertie") and southern portions of certain transmission lines connecting areas of western Canada with the Region, obtains transmission revenues from providing Point-to-Point service to power marketers who need Bonneville transmission service to effect power sales and related transactions inside and outside the Region.

While it is difficult to generalize as to the cost of transmission service needed to effect various power transactions, a useful point of reference may be the cost borne by certain Regional full requirements Preference Customers of Bonneville's. These customers pay roughly $4.00 to $4.50 per megawatt hour for Network Integration transmission and ancillary services to Bonneville to provide delivery of firm power that Bonneville sells at the PF rate, which is currently priced at roughly $30.00 to $34.00 per megawatt hour, depending on type of service and exclusive of transmission. Other customers, e.g., marketers using Point-to-Point service to transmit non-Federal power, pay approximately $3.50 per megawatt hour for transmission and ancillary services.

Bonneville's Transmission System

The Federal System includes the transmission system that is owned, operated and maintained by Bonneville as well as the Federal 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 over 300 substations and other related facilities that are located in Washington, Oregon, Idaho, and portions of Montana, Wyoming and northern California. The Federal transmission system includes an integrated network for service within the Pacific Northwest ("Network"), and approximately 80% of the northern portion (north of California and Nevada) of the combined Southern Intertie. 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 Pacific Northwest and Pacific Southwest and provide the primary bulk transmission link between the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4800 megawatts of capacity ("MW"), and in the south to north direction is 3675 MW. The rated transfer capability of the DC line in both directions is 3100 MW. The operating transfer capability (or reliability transfer capability) of these facilities varies by generation patterns, weather conditions, load conditions and system outages.

The Federal System transmission facilities are used to deliver power between resources and loads within the Pacific Northwest, and to transmit power between and among the Region, western Canada and the Pacific Southwest. Bonneville's Transmission Business Line provides transmission services and transmission reliability (ancillary) services to many customers. These customers include Bonneville's Power Business Line for its out-of-Region sales; 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 marketers; in-Region purchasers of Federal System power such as Preference Customers and DSIs; and generators, power marketers and utilities that seek to transmit power into, out of, or through the Region.

Bonneville constructed the Federal transmission system and is responsible for its operation and maintenance, and makes investments necessary to maintain the electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by regional reliability practices. From time to time, Bonneville undertakes investments or reinforcements to or changes in the planning and operation of its transmission facilities to comply with the transmission system reliability criteria.

Bonneville continually monitors its transmission system and evaluates cost-effective responses needed for system stability and reliability on a long-term planning basis. A number of conditions, actions, and events could affect the electric transfer capability of Bonneville's transmission system and diminish the capacity of the system to a level that could require remedial measures. 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 users of the transmission system, including Bonneville's Power Business Line.

Transmission Infrastructure Program

Given its importance to electrical service both in the Pacific Northwest Region and the wider western United States, the Federal Transmission System must have the capacity to carry the power around the clock, in compliance with national reliability standards, and do this under a variety of stress conditions. Despite significant growth in the Pacific Northwest population and economy, there was no substantial transmission construction in the Pacific Northwest between 1987 and 1992. Load growth on the system has been about 1.8% a year and transmission use has grown about 2% a year. Furthermore, deregulation of the wholesale power industry in 1992 altered the way utilities do business. Utilities are now required to operate and manage their power and transmission systems as separate businesses, guaranteeing that all power generators have equal access to transmission. This increased the amount of transmission system transactions by nearly 5 percent a year while peak use of the electrical system increased by almost 2 percent a year.

In light of the increasing demand on the Federal Transmission System, critical paths on the Northwest transmission grid are now congested and the system is nearing or at capacity. Congested paths occur when demand for power exceeds what the transmission system can safely handle. With increased congestion, computer models and monitoring show the grid to be less robust and harder to control after an emergency, such as the collapse of a transmission tower.

As demand for power increases, Bonneville's transmission system may also no longer be able to meet national and regional reliability standards. These standards prescribe how reliable the transmission grid must be. Organizations such as the North American Electric Reliability Council develop these standards with input from utilities, regulators, consumers and other interested parties to define what events Bonneville should plan for. Some standards were made even more stringent after transmission outages in the summer of 1996 that began on the Federal Transmission System and led to blackouts in nine western states.

Congestion is not only a risk to public safety and electric system reliability, it reduces the ability of Bonneville, as the power marketing agent for the hydroelectric power from the Federally-owned hydroelectric dams in Pacific Northwest, to get low-cost energy to market.

In view of the foregoing considerations, Bonneville developed a "Transmission Infrastructure Program" to evaluate a number of key infrastructure projects to improve the reliability of the Northwest transmission system and to meet the region's future power needs. In 2001, Bonneville identified 20 projects, including the Project, needed to shore up the Region's transmission system. An Infrastructure Technical Review Committee, consisting of transmission experts from Northwest utilities, evaluated the projects on economic and technical grounds to ensure the projects were necessary, properly prioritized and designed to provide cost-effective, reliable service to the Region. The committee then narrowed the initial list to focus on infrastructure improvement projects deemed critical to keeping the Northwest transmission grid operating reliably and economically. It also recommended that these projects receive top priority for near-term investment and construction.

Each infrastructure project, including the Project, has been or is being designed to assure compliance with recently adopted national and regional reliability standards. Some of the identified projects were identified as needed for the integration of new generation projects, others were identified as projects that will have more generalized network reliability and safety benefits.

With reference to the guidance of the Technical Review Committee and in light of the delay and suspension of new generation construction, Bonneville has focused its infrastructure efforts primarily on critical transmission projects needed to maintain reliability. Projects proposed to provide additional, long-term firm transmission service for new generation are on hold but are expected to move forward when funding approaches can be finalized. A number of issues will have to be resolved prior to Bonneville's committing to its transmission investment levels, including identifying sources of funding and determining which investments should be made by Bonneville. With regard to the financing of the foregoing projects, Bonneville is currently requiring that those applicants requesting that Bonneville provide transmission for new generating facilities bear the risk of stranded transmission interconnection costs by prepaying the related transmission investments and obtaining credits to their transmission bills from Bonneville.

Bonneville initiated construction on two critical system reliability upgrade projects in calendar year 2003. The third such critical system reliability project is the Project. With regard to congestion and reliability investments such as the Project, Bonneville expects to finance such investments with a mix of United States Treasury borrowing authority and sources of non-United States Treasury financing, such as the lease-purchase structure used to secure the financing for the Project. For a description of the Project and the Lease Agreement, see "THE PROJECT AND USE OF PROCEEDS," and "THE LEASE AGREEMENT."

Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $302 million a year over the four fiscal years commencing October 1, 2003.

Non-discriminatory Transmission Access and Separation of the Business Lines

In general, the thrust of regulatory changes in the 1990s, both by Congress and FERC, has been to encourage 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 functions. EPA-1992 amended section 211/212 of the Federal Power Act 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 with respect to the transmitting utility's own use of its transmission system.

While Bonneville is not generally subject to the Federal Power Act, Bonneville is a "transmitting utility" under the EPA-1992 amendments to sections 211/212 of the Federal Power Act. Therefore FERC may order Bonneville to provide others with transmission access over the Federal System transmission facilities. FERC's authority also includes the ability to 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 relating to 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 211/212 are to be established by Bonneville, rather than by FERC, and 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 April 1996, FERC issued an order, "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 jurisdictional utilities to adopt the tariff. Order 888 also included a "reciprocity" provision that allows non-jurisdictional utilities to obtain non-discriminatory open access from transmitting utilities if the non-jurisdictional utility submits to FERC for its approval (i) an open access transmission tariff that substantially conforms to the *pro forma* tariff and (ii) transmission rates that are comparable to the rates the non-jurisdictional utility applies to itself.

Bonneville is a non-jurisdictional utility. Notwithstanding the limited applicability of FERC Order 888 to Bonneville, however, in 1996, Bonneville voluntarily adopted terms and conditions for a non-discriminatory open access transmission tariff and filed such tariff with FERC seeking a reciprocity order. Bonneville's tariff offers transmission service to Bonneville's Power Business Line and other transmission users at the same tariff terms and conditions, and at the same rates. In March 1999, FERC found the tariff to be an acceptable reciprocity tariff. Bonneville has since revised and filed with FERC a new, open access tariff that conforms more closely to FERC's current *pro forma* open access tariff. In orders issued in March 2001 and September 2001, FERC found Bonneville's new tariff to be an acceptable reciprocity tariff. The revised open access transmission tariff became effective beginning October 1, 2001.

In April 1996, FERC also issued an order ("Order 889") that sets forth "standards of conduct" for jurisdictional utilities that are transmission providers and 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 owner do not obtain unfair market advantage by having preferential access to information regarding the transmission owner's transmission operations. While not subject to Order 889, Bonneville nonetheless separated its transmission and power functions into separate business lines in conformance with that order and has developed and submitted standards of conduct for FERC's review. FERC found Bonneville's standards of conduct to be acceptable in February 1999.

Bonneville's Transmission and Ancillary Service Rates

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

Bonneville's transmission rates must also equitably allocate the cost of the Federal transmission system between Federal System power and non-federal power using the transmission system. Since 1996, the Power Business Line and customers transmitting Federal System power are charged the same transmission rates as are charged customers transmitting non-federal power. In compliance with the statutory requirements for its rates, Bonneville separately accounts for transmission and power revenues and costs. Since 1996, it also sets separate transmission and power rates to recover their respective costs.

Bonneville's transmission and ancillary services rates for fiscal years 2004-2005 were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. In addition to approving Bonneville's transmission rates under the Northwest Power Act, FERC stated that the rates and tariffs fulfill standards for open, nondiscriminatory transmission access. The 2002 transmission rates were not challenged in litigation. In Spring 2004, Bonneville will commence proceedings for transmission rates and tariffs for the next transmission rate period.

Bonneville's Participation in a Regional Transmission Organization

Following the issuance in May 1999 of a notice of proposed rulemaking on regional transmission organizations ("RTOs"), in January 2000 FERC issued a final rule on RTOs that establishes minimum characteristics and functions for an RTO and requires that each jurisdictional utility make certain filings regarding the formation of and participation in an RTO. The order, "Order 2000," encouraged each jurisdictional utility (Bonneville is not a jurisdictional utility) to file a proposal for an RTO that would be operational by December 15, 2001.

In March 2000, Bonneville, six Pacific Northwest IOUs and two Nevada utilities (collectively, the "Filing Utilities") agreed to a set of RTO Principles and a general description of an RTO Form and Structure, and proposed to work to submit an RTO proposal to FERC. The RTO Principles provide, among other things, that "[w]ith respect to the Bonneville Power Administration, the RTO shall be designed so as (a) not to increase the risk to the United States Treasury or to third party bondholders and (b) to avoid financial restructuring of low-cost Bonneville debt."

In October 2000, the Filing Utilities filed with FERC a response to Order 2000 proposing a form of governance and a geographic scope of a nonprofit RTO (to be named RTO West) for the transmission systems of transmission owners willing to participate and located within the United States portion of the Northwest Power Pool ("Stage 1 proposal"). This region is composed of Washington, Oregon, Idaho, Utah, Nevada, Montana and western Wyoming. On April 26, 2001, FERC granted preliminary approval of the proposals for governance and geographic scope. On March 29, 2002, the Filing Utilities, along with the British Columbia Hydro and Power Authority, filed additional elements of their RTO West proposal ("Stage 2 proposal") for FERC approval. In September 2002, FERC approved a majority of the Stage 2 proposal, including the Company Rate concept with an 8-year transition period, voluntary conversion of existing transmission contracts to RTO West Tariff service, and a modified congestion management proposal. FERC rejected a broad proposal for all the terms of the operating agreement to govern in the event of a conflict with the RTO West Tariff. However, FERC acknowledged the Filing Utilities' interest in protecting certain elements of their proposed arrangement from future, unilateral FERC modification and indicated its willingness to consider a more narrowly defined list of provisions that warranted protection.

Under the RTO West proposal, Bonneville would retain ownership of all of the Federal System transmission assets, but would transfer planning and operational control over most of such facilities to RTO West and establish RTO West as the exclusive provider of transmission service over such facilities. Under the current draft operating agreement, Bonneville would retain the responsibility for maintaining the Federal System transmission assets. Investments to expand the Federal transmission system could be accomplished by Bonneville or third parties, with RTO West allocating the expansion costs to transmission owners who benefit from the expansion, including Bonneville. For a period of at least eight years after commencement of service by RTO West ("Company Rate Period"), costs for the use of Bonneville's transmission facilities would be recovered through Bonneville's own "Company Rates." ("Company Rates" are rates that are individually established to recover each owner's transmission revenue requirement under laws applicable to the related owner.) The draft operating agreement provides that Bonneville would set its own costs and billing determinants, which would be used to derive Company Rates for recovery of Bonneville's costs from its own loads. If, after the Company Rate Period, RTO West determines to implement a rate structure other than the Company Rate, Bonneville would continue to establish its charges to be recovered by RTO West through rates adequate to (i) meet Bonneville's annual revenue requirement and (ii) satisfy all obligations of Bonneville for the net billing and payment of costs for nuclear generating projects owned in whole or in part by Energy Northwest or the Eugene Water and Electric Board. In the opinion of the General Counsel to Bonneville, assuming the entry by Bonneville into the draft operating agreement, the draft operating agreement would be consistent with Bonneville's obligation to recover its costs, and would not interfere with Bonneville's authority to recover "stranded costs," which are defined in the draft operating agreement to include power function costs. See "—POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Recovery of Stranded Power Function Costs." Under the draft operating agreement, no directive of RTO West may require Bonneville to violate its obligations under applicable statutes or regulations.

In its April 2001 order, FERC acknowledged the need to provide assurances and protections to Bonneville with respect to its ability to continue to meet its statutory, treaty, contractual and other responsibilities. FERC also clarified that its jurisdiction over Bonneville is limited with regard to RTO formation, and that Bonneville's authority to participate in RTO West is not subject to review by FERC. The General Counsel of DOE issued an opinion in May 1999, that Bonneville's participation in or affiliation with a regional transmission entity would not require federal legislation, provided the terms of such participation do not interfere with Bonneville's ability to perform its statutory duties.

FERC also found that, while RTO West will have the exclusive authority to make filings under section 205 of the Federal Power Act (applicable to jurisdictional utilities) that apply to rates, terms and conditions of RTO West Tariff service, it acknowledged that Bonneville is not a Federal Power Act jurisdictional utility and clarified that Bonneville's rates are established by the Administrator, and approved or disapproved by FERC. FERC also does not have the power to modify Bonneville's rates under the current statutes applicable to Bonneville.

In its April 2001 order, FERC rejected an RTO West proposal limiting the liability of the RTO West participants (including Bonneville) through a "no fault" liability structure for electric system property damage, liability limitations for tariff service interruptions, and indemnity provisions for bodily injury claims. In its September 2002 order, FERC reversed itself and determined that the Filing Utilities could propose limited liability provisions when they file the RTO West tariff. The RTO West tariff has not yet been filed. In the opinion of the General Counsel to Bonneville, assuming the entry by Bonneville into the draft operating agreement, the Federal Torts Claims Act, which limits the grounds and manner in which the United States may be sued for actions sounding in tort, would continue to apply to actions taken by Bonneville in connection with RTO West. Depending on the extent to which FERC approves tariff provisions limiting liability, liability for actions taken by RTO West could subject RTO West to liability and such costs could be allocated to Bonneville as a charge in applicable rates and tariffs.

In February 2003, two customer groups representing many of Bonneville's Preference Customers filed a petition for review in the United States Court of Appeals for the District of Columbia. This petition for review requests the court to modify or set aside prior FERC rulings relating to the RTO West proposal. The petition did not identify specific grounds for the review. On June 19, 2003, the United States Court of Appeals for the District of Columbia dismissed the case on the basis that the case was not ripe for review.

The Filing Utilities have recently resumed their engagement with regional stakeholders through the Regional Representatives Group process to gauge the level of regional support for moving forward with the RTO West proposal as considered by FERC. These discussions are ongoing, and no further RTO West proposals have been filed with FERC.

MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES

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 incorporates the provisions of other Bonneville organic statutes, including the Transmission System Act and the Flood Control Act. 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 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 reasoning 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.

FERC's review of Bonneville's firm power rates, Regional non-firm energy rates and transmission rates involves three standards set out in the Northwest Power Act. These standards require FERC to confirm and approve these Bonneville rates based on findings that such rates: (1) 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; (2) are based on Bonneville's total system costs; and (3) 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 the cost allocation for rates for firm power and Regional non-firm energy. For a discussion of FERC regulations related to transmission access and rates, see "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines."

In confirming and approving Bonneville's rates for non-firm energy sold for use outside the Region, FERC reviews whether such rates were designed: (1) having regard to the recovery of cost of generation and transmission of such electric energy; (2) so as to encourage the most widespread use of Bonneville power; (3) to provide the lowest possible rates to consumers consistent with sound business principles; and (4) in a manner which protects the interests of the United States in amortizing its investments in the Federal System within a reasonable period. The Northwest Power Act provides for the possibility of an additional rate hearing before FERC on non-regional non-firm energy rates, based on the record developed at Bonneville.

Upon reviewing Bonneville's rates, 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 have to reformulate the proposed rate to comply with the statutory ratemaking standards. If FERC were to have given Bonneville interim approval, Bonneville may be required to refund the difference between the interim rate charged and any such 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.

Judicial Review of Federal Energy Regulatory Commission Final Decision

FERC's final approval of a proposed Bonneville rate is a final action subject to direct, exclusive review by the Ninth Circuit Court. 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 have to 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: (1) to public and certain federal agency customers; (2) to direct service industrial customers; and (3) for those portions of their load which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line and — Residential Exchange Program." The rates for power sold to these respective customers 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 may decide are applicable to such sales. Bonneville also sells similarly priced surplus firm power outside the Northwest, primarily to California, under short-term power sales that allow for flexible prices, or under long-term contract rates.

Non-Firm Energy

Non-firm energy is priced in accordance with the statutory standards (contained in the Northwest Power Act) applicable to such sales, as discussed above. Non-firm energy is available within and without the Pacific Northwest, with most sales being made to California utilities that use non-firm energy to displace the operation of more expensive thermal resources.

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

Bonneville must comply with the National Environmental Policy Act ("NEPA"), which requires that federal agencies conduct an environmental review of a proposed federal action and prepare an environmental impact statement if the action proposed may significantly affect the quality of the human environment. NEPA may require that Bonneville follow statutory procedures prior to deciding whether to implement an action. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Toxic Substance Control Act ("TSCA") and applicable state statutes and regulations, as well as amendments thereto, may result in Bonneville incurring unplanned costs to investigate and clean up sites where hazardous substances have been released or disposed of. There are currently three such sites. One of these sites is a Bonneville-operated facility awaiting determination by the EPA, but two are non-Bonneville sites wherein Bonneville has been identified as potentially a responsible party. Normally environmental protection costs are budgeted and do not exceed $150,000 per site. While Bonneville anticipates that additional potential costs will be between $1 million and $2 million total over several years, Bonneville cannot assure the ultimate level of costs that may be incurred under these statutes.

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 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.

Regulation of stream flows by the Canadian reservoirs enables six federal and five non-federal dams downstream in the United States to generate more usable, firm electric power. This increase in firm power is referred to as 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 on the border near Oliver, British Columbia, unless the United States Entity and the Canadian Entity agree to other arrangements. The United States Entity and Canadian Entity signed the "Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 15, 2024" (the "Entity Agreement") on November 20, 1996, which was subsequently revised on March 29, 1999. As a result, the United States Entity does not have to build the proposed transmission line to a point near Oliver, British Columbia, in order to return the Canadian Entitlement.

The United States Entity and Canadian Entities have 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 by the executive branches of the United States and Canadian governments through an exchange of diplomatic notes, which occurred on March 29, 1999. The United States Entity's obligation to return the Canadian Entitlement to the border under the Entity Agreement is not dependent upon the authority to directly dispose of the Canadian Entitlement in the United States.

Proposals for Federal 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 regulation comparable to regulation 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 its 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 Congress have included privatizing the federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at federal hydroelectric projects, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates and submitting Bonneville's power marketing to varying degrees of FERC regulation. None of these bills or proposals were enacted into law.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such proposals, if enacted, could affect Bonneville's obligation with respect to the Lease Agreement. However, Bonneville believes that any major electric industry restructuring affecting its obligations with respect to the Lease Agreement would require federal legislation.

Bonneville is a federal agency. It is subject to direction or guidance in a number of respects from the U.S. Office of Management and Budget, DOE, FERC, the United States Treasury and other federal agencies. Bonneville is frequently the subject of, or would be otherwise 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.

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 (see "Bonneville Borrowing Authority"), 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 federal 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, 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 Northwest, construction of major transmission facilities within the Northwest, construction of certain fish and wildlife facilities, condemnation of operating transmission facilities and acquisition of a major resource that is not consistent with the Power Plan.

In the opinion of the General Counsel to Bonneville, the Project as described herein is not a "major transmission facility" and, therefore, Bonneville's entry into the Lease Agreement and Construction Agency Agreement is not conditioned on any further Congressional action.

The Federal System Investment

The total cost of the multipurpose Corps and Bureau projects 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 Bureau 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, in addition to certain capital conservation and fish and wildlife costs since 1980, have been funded through the use of Bonneville's borrowing authority.

Bonneville is required by statute to establish rates that are sufficient to repay the federal investment in the power facilities of the Federal System 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, 2003, Bonneville had repaid $5.5 billion of principal of the Federal System investment and has $6.6 billion principal amount outstanding with regard to such appropriated investments.

Bonneville Borrowing Authority

In February 2003, Congress enacted and the President signed into law a $700 million increase in Bonneville's authority to borrow from the United States Treasury. The new law increases to $4.45 billion the aggregate principal amount of bonds Bonneville is authorized to sell to the United States Treasury and to have outstanding at any one time. The new increment of borrowing authority is to be used for Bonneville's transmission capital program and to implement the Administrator's authorities under the Northwest Power Act.

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.70 billion of bonds were outstanding as of September 30, 2003. 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 average megawatts. Of the $4.45 billion in U.S. Treasury borrowing authority, $1.25 billion is available for renewable resources and conservation purposes and $3.2 billion is available for Bonneville's transmission capital program and to implement the Administrator'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 September 30, 2003, the interest rates on the outstanding bonds ranged from 2.30% to 8.55% with a weighted average interest rate of approximately 5.32%. The original terms of the outstanding bonds vary from 3 to 40 years. The term of the bonds is limited by the average expected service life of the associated investment: 40 years for transmission facilities, 75 years for Corps and Bureau capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. All bonds with original maturities greater than 15 years may be called early, except for three bonds totaling $258.8 million.

Debt Optimization Proposal

In the spring of 2000, Bonneville presented a "Debt Optimization Proposal" to Energy Northwest. The proposal, which was agreed to by Energy Northwest, involves the extension of the final maturity of debt issued for the Columbia Generating Station, the debt service of which Bonneville secures under net billing agreements as described herein. In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it also incorporated an increase in the average life of Projects 1 and 3 Net Billed Bonds as a refinancing program objective for any future refinancing of such bonds.

Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's rate payers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs at the lowest cost to rate payers; and (3) maintaining sufficient financial flexibility to handle Bonneville's financial requirements. Implementing the proposal is intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's high interest Federal debt and reduce Bonneville's overall fixed costs.

Order in Which Bonneville's Costs Are Met

Bonneville's operating revenues include net billing credits provided by Bonneville, under certain Net Billing Agreements, to certain Participants in return for payments by such customers to Energy Northwest to meet certain costs of its Columbia Generating Station, Project 1 and Project 3, and to the City of Eugene, Oregon, Water and Electric Board ("EWEB") to meet certain costs of the Trojan Nuclear Project, a terminated nuclear project owned in part by EWEB. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Trojan Nuclear Project, Project 1, the Columbia Generating Station and Project 3, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. These credits reduce the amount of cash revenues Bonneville has available to pay other obligations, including payments under the Lease Agreement.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System 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) repayment of appropriated amounts to the Corps and the Bureau for costs that are allocated to 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 2003 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.057 billion in fiscal year 2003, approximately $315 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Proposal through the use of cash flows derived from reduced Net Billed Project debt service in such fiscal year. Such Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. In accordance with the Debt Optimization Proposal, Bonneville plans to make similar advance amortization payments to the United States Treasury in fiscal year 2004 and in subsequent fiscal years. In addition to the advance amortization arising under the Debt Optimization Proposal, Bonneville amortized ahead of schedule about $13 million principal amount of its appropriations repayment responsibility relating to certain transmission facilities that Bonneville sold in fiscal year 2003.

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, 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 Agreement and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury for the costs described in items (i) to (iv) in the preceding paragraph.

Bonneville is authorized to enter into new agreements to provide for additional net billing of its customers' bills. Nevertheless, because Bonneville is now able to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount in the Bonneville Fund and available borrowing authority, the primary reason for using net billing no longer exists. Bonneville has no present plans to enter into new agreements requiring net billing to fund resource acquisitions or other capital program investments.

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 and then defer current interest payments to the United States Treasury. When Bonneville defers an interest payment, the deferred amount is assigned a market interest rate determined by the Secretary of the United States Treasury and must be repaid before Bonneville can make any other repayment of principal to the United States Treasury. See the table under the heading "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" for historical United States Treasury payments.

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 the Bureau and the U.S. Fish and Wildlife Service ("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 Bureau federal system operations and maintenance activities. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2003 were $54 million for the Bureau, $129 million for the Corps, and $15 million for the Fish and Wildlife Service.

Bonneville believes that, in contrast to prior practice, the direct payment approach increases 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 becomes necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct payments 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 payments could be made to the exclusion of non-federal payments that would otherwise have been paid under historical practice. A result of any direct payment obligation by Bonneville is that there would 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, during the terms of the direct payment agreements, Bonneville expects to have roughly $500 to $800 million in scheduled annual payments to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses.

Hedging and Derivative Instrument Activities and Policies

Bonneville's financial success depends on its ability to manage business and financial risks associated with its commercial operations in a changing competitive environment. Effective management of electricity, interest rate and natural gas price risk can assist in efforts to manage Bonneville's revenues and expenses.

Bonneville is affected by price risk associated with commodities and streamflow uncertainty that in turn affect the predictability and stability of its revenues. These commodities include electricity, and natural gas, and to a much lesser extent than was the case historically, aluminum. Bonneville desires to manage price and revenue risks resulting from electricity and natural gas volatility, hydro supply uncertainty and interest rate risk.

Bonneville seeks to ensure that its hedging of various revenue and price risks be conducted in an intelligent, business-like manner. To this end, Bonneville adopted its Hedging Policy, as amended from time to time, to describe the guidelines, controls and management structure when there is a decision to hedge price and revenue risk in financial instruments. Bonneville's Hedging Policy allows the use of financial instruments such as commodity futures, options and swaps used to hedge price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development, and interest rates. From time to time, Bonneville uses or may use financial instruments in the form of Over-the-Counter electricity swap agreements and options, Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy, and interest rate swaps to hedge interest rate positions or to more efficiently manage Bonneville's overall debt portfolio. In general, the Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under certain procedures set forth in the Policy. In addition, the Policy set forth a limited exception for the use of financial instruments relating to interest rate management techniques to manage Bonneville's interest rate costs, including by means of interest rate swaps to effect the synthetic refunding of Bonneville's direct and indirect debt obligations. The Policy does not apply to physical (power) transactions

In January 2003, Bonneville entered into two floating to fixed interest rate swap agreements with an aggregate notional amount of $500 million. The swap agreements were entered into in connection with, and are in an aggregate notional principal amount approximately equal to, the principal amount of certain variable rate Net Billed Bonds issued by Energy Northwest in April 2003 (the "Related Bonds"). Pursuant to these swap agreements, Bonneville is required to make fixed rate payments to each of two swap providers and will receive variable rate payments from such swap providers. One of the swaps has a term of ten years and the other has a term of fifteen years. The Related Bonds are variable rate bonds having final maturities of approximately fifteen years. Under certain circumstances, Bonneville and/or the swap provider may terminate the respective swap agreement, at which time Bonneville may be required to make a payment to the swap provider depending on the mark-to-market value of the swap at termination. Each of the swap providers is currently rated at or above the Aa category by Moody's Investor Service and at or above the AA category by Standard & Poor's Credit Market Services, a Division of The McGraw-Hill Companies Inc.

Historical Federal System Financial Data

Federal System historical financial data for fiscal years 2001 through 2003 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information has been derived from the annual audited financial statements of the Federal System and should be read in conjunction with Appendix B-1. Federal System financial statements are prepared in conformity with generally accepted accounting principles. The audited Financial Statements of the Federal System (which include accounts of Bonneville as well as those of the generating facilities of the Corps and the Bureau, for which Bonneville is the power marketing agency) as of September 30, 2003 and 2002 and for the three years ended September 30, 2003 are included as Appendix B-1 hereto.

Federal System Statement of Revenues and Expenses
(Actual Dollars in Thousands)

Fiscal year ending September 30,	2003	2002	2001
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Publicly-owned utilities [1]	$1,723,138	$ 1,797,496	$ 939,362
Aluminum industry	18,480	58,454	420,694
Investor-owned utilities	435,709	377,789	700,836
Other power sales	1,211	1,293	972
Sales outside the Northwest Region [2]	628,242	638,261	1,084,077
Total Sales of Electric Power	2,806,780	2,873,293	3,145,940
Transmission and other revenues [3]	805,324	660,436	1,132,729
Total Operating Revenues	3,612,104	3,533,729	4,278,669
Operating Expenses:			
Bonneville O&M [4]	607,616	775,077	530,618
Purchased Power	1,043,009	1,286,867	2,291,961
Corps, Bureau and Fish & Wildlife O&M [5]	198,539	198,055	184,922
Non-Federal entities O&M — net billed [6]	208,535	167,026	208,839
Non-Federal entities O&M — non-net billed [7]	39,864	35,566	30,719
Total Operation and Maintenance	2,097,563	2,462,591	3,247,059
Net billed debt service	104,329	213,919	455,397
Non-net billed debt service	15,205	16,256	21,818
Non-Federal Projects Debt Service [8]	119,534	230,175	477,215
Federal Projects Depreciation	350,025	335,205	323,314
Residential Exchange [9]	143,967	143,983	68,082
Total Operating Expenses	2,711,089	3,171,954	4,115,670
Net Operating Revenues	901,015	361,775	162,999
Interest Expense:			
Appropriated Funds	280,094	325,551	317,213
Long-term debt	166,598	151,997	129,159
Capitalization Adjustment [10]	(67,703)	(67,356)	(68,784)
Allowance for funds used during construction	(33,398)	(57,892)	(45,679)
Net Interest Expense	345,591	352,300	331,909
Cumulative Effect of SFAS 133 [11]			(168,491)
Net Revenues/(Expenses)	$ 555,424	$ 9,475	$ (337,401)
Total Sales — average megawatts (Net of Residential Exchange Program)	10,764	11,732	10,302

(1) This customer group includes municipalities, public utility districts and rural electric cooperatives in the Region.

(2) In general, revenues from sales outside the Northwest are highly dependent upon stream flows in the Columbia River Basin, which affect the amount of seasonal surplus energy available for sale, and upon the costs of generating power with alternative fuels, which affect the price Bonneville can obtain for its exported non-firm energy and surplus firm power.

(3) Bonneville obtains revenues from the provision of transmission and other related services. 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 credits Bonneville receives to its United States Treasury repayment obligation. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. In addition, under Financial Accounting Standards Board Statement of Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville also recorded as revenue in Fiscal Years 2001, 2002 and 2003, positive Mark-to-Market Amounts of $55.3 million, $38.4 million and $47.9 million, respectively. See Footnote 11 below.

(4) Bonneville operations and maintenance expenses include the costs of Bonneville's transmission system, operation and maintenance program, energy resources, power marketing, and fish and wildlife programs.

(5) Corps, Bureau and Fish & Wildlife operations and maintenance expenses include the costs for the Corps and Bureau generating facilities included in the Federal System as well as expenses incurred by the U.S. Fish & Wildlife Service in connection with the Federal System.

(6) 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 certain capitalized contracts, the costs of which are net-billed.

(7) The Non-Federal entities O&M – non-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 certain capitalized contracts, the costs of which are not net-billed.

(8) These amounts include payment by Bonneville for all or a part of the generating capability of, and debt service on, four nuclear power generating projects (three of which are terminated). They are Energy Northwest's Project 1, Project 3, and the Columbia Generating Station, and the City of Eugene Water and Electric Board's 30% ownership share of the Trojan Nuclear Project. These amounts also include payment by Bonneville with respect to several small generating and conservation projects.

(9) See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line" and "—Residential Exchange Program."

(10) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing federal appropriations under legislation enacted in 1996.

(11) On October 1, 2000, the date of adoption by Bonneville of SFAS 133, Bonneville recorded a cumulative-effect adjustment of $168,491,000 loss to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted primarily of transactions known as "bookouts" that the FASB initially determined should be fair valued in net revenue (expense). While authoritative accounting guidance in this area continued to emerge during fiscal year 2001, Bonneville management elected to apply the most current guidance available related to SFAS 133, as amended.

Management Discussion of Operating Results

Bonneville had positive net revenues of $555 million in fiscal year 2003, an increase of approximately $545 million over fiscal year 2002. Bonneville's Debt Optimization program and other debt management actions contributed significantly to the substantial increase in net revenues. Without the program, other debt management actions, and the effects of SFAS 133, net revenues would have been $37 million for fiscal year 2003. Total operating revenues increased by $78 million, or 2% from the previous fiscal year due to greater sales to Regional IOUs and increased United States Treasury credits derived under section 4(h)(10)(C) of the Northwest Power Act for fish mitigation, even though there was both reduced hydro generation and reduced power sales when compared to fiscal year 2002. However, the average price for discretionary surplus power sales rose from $26 per megawatt hour to $37 per megawatt hour, an increase of 42%. United States Treasury credits under section 4(h)(10)(C) of the Northwest Power Act increased from $38 million to $175 million in 2003, including $79 million from the Fish Cost Contingency Fund, which was not accessed in fiscal year 2002 and is now fully depleted. Credits for fish mitigation increased due to below-average water conditions and increased power purchases that result from reduced hydro supply. For a description of 4(h)(10)(C) credits and the Contingency Fund see "—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

Total operating expenses in fiscal year 2003 were approximately $460 million lower as compared to fiscal year 2002, a decrease of about 14%. This was largely due to decreased Non-Federal Projects Debt Service, which decreased by $111 million or 48% because of the deferral of some principal payments due in fiscal year 2003 into the future, primarily as a result of continued implementation of the Debt Optimization Proposal. Lower interest rates through refinancing some of the Non-Federal debt also contributed to the decline in debt service. Net Interest Expense on Federal debt declined by $7 million compared to fiscal year 2002 due to generally lower interest rates on borrowings from the United States Treasury to finance federal generating and transmission projects. Total operations and maintenance costs, excluding Purchased Power, also decreased by $121 million, or 9% from the previous year. Lower bad debt expense and general and administrative expense were the main factors that led to this decrease. Purchased Power also decreased by $244 million, or 19%, in view of comparatively lower prices for the power purchased by Bonneville and the release of Bonneville from certain power purchase commitments as the result of a settlement between Bonneville and Enron Power Marketing Corp. in its bankruptcy proceedings.

In fiscal year 2002, Bonneville had positive net revenues of almost $10 million, an increase of approximately $347 million over fiscal year 2001 when Bonneville had negative net revenues of approximately $337 million. Total operating revenues declined by $745 million, or 17%, from the previous year due to lower market prices for discretionary sales of surplus power and a 94% decline in fish credits under section 4(h)(10)(C) of the Northwest Power Act. These lower market prices resulted in a decrease of $446 million, or 41%, in revenues from sales outside the Northwest. In addition, revenues from aluminum company DSIs decreased by $362 million, or 86%, largely due to the purchase back by Bonneville of some of its power sales to DSIs and curtailments of purchases by some DSIs. The $323 million, or 46%, decline in revenues from Regional IOUs in fiscal year 2002 stemmed largely from payments arising under agreements between Bonneville and the Regional IOUs to settle Bonneville's Residential Exchange obligations and the purchase back by Bonneville of some of its power sales to Regional IOUs. This decline in revenues was somewhat mitigated by the amount of revenues from sales to publicly-owned utilities, which in fiscal year 2002 increased by $858 million, or 91%, due to a substantial rate increase at the beginning of the new rate period (October 1, 2002), and an increase in the amount of power Bonneville sold to this customer class. The $472 million, or 42%, decline over fiscal year 2001 in revenues from transmission and other related services was the result of lower estimated Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act as these repayment credits declined by 94% as noted immediately above. Applicable criteria did not permit use of the Contingency Fund whereas $247 million was drawn from the fund, in the form of United States Treasury repayment credits, during fiscal year 2001.

Total operating expenses in fiscal year 2002 were approximately $3.2 billion, a decrease of $944 million, or 23%, when compared to fiscal year 2001. This was largely due to lower market prices for power purchased by Bonneville. Purchased power expense declined by $1 billion, or 44%, in 2002, due to a 15% decrease in the amount of power purchased by Bonneville as water conditions returned to average levels from the historical low levels of the prior fiscal year, as well as a decrease in the average cost of purchased power. In addition, net billed debt service decreased by approximately $242 million, or 53%, due primarily to the refinancing and restructuring of a portion of the outstanding net billed debt. Non-Federal entities O&M-net billed expense declined by $42 million primarily due to reduced operating expense related to Columbia Generating Station. However, Bonneville operations and maintenance expenses were up by $244 million dollars, or 46%, in fiscal year 2002, primarily due to increased budgets for fish and wildlife, resource conservation management and bad debt expense.

Statement of Non-Federal Project Debt Service Coverage

The Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments uses the Federal System Statement of Revenue and Expenses to develop a non-federal Project debt service coverage ratio ("Non-Federal Project 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 Project debt service is defined as total operating revenues less operating expenses (see footnote 9 to the Statement of Non-Federal Project Debt Service Coverage below). 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 Project 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. For a discussion of certain direct payments by Bonneville for Federal System operations and maintenance, which payments reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay. See "— Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments
(Actual Dollars in Thousands)

Fiscal Years ending September 30,	2003	2002	2001
Total Operating Revenues	$3,612,104	$ 3,533,729	$4,278,669
Less: Operating Expense[1]	2,042,991	2,408,520	3,130,219
Net Funds Available for Non-Federal Project Debt Service	1,569,113	1,125,209	1,148,450
Less: Total Non-Federal Project Debt Service[2]	119,534	230,175	477,215
Revenue Available for Treasury	1,449,579	895,034	671,235
Amount Paid to Treasury:			
Corps and Bureau O&M[3]	198,539	198,055	184,922
Net Interest Expense[4]	345,591	352,300	331,909
Capitalization Adjustment[5]	67,703	67,356	68,784
Allowance for Funds Used During Construction[4] [6]	18,641	15,061	12,479
Amortization of Principal	543,747	505,012	210,127
Total Amount Allocated for Payment to Treasury[7]	1,174,221	1,137,784	808,221
Revenues Available for Other Purposes[8]	275,358	(242,750)	(136,986)
Non-Federal Project Debt Service Coverage Ratio[9]	13.1	4.9	2.4
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[10]	1.7	1.3	1.2

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

(2) Includes net billed and non-net billed debt service. Non-net billed debt service amounted to $21.8 million, $16.3 million and $15.2 million for fiscal years 2001, 2002 and 2003, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Bureau and Fish & Wildlife for fiscal years 2001, 2002 and 2003. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(4) Amounts shown are calculated on an accrual basis.

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

(6) The Allowance for Funds Used During Construction that Bonneville pays to the United States Treasury is Bonneville's portion of the interest component on the Federal investment during the construction period.

(7) Bonneville's payments to the United States Treasury in fiscal years 2001, 2002 and 2003 were $729 million, $1.056 billion and $1.057 billion, respectively. In fiscal years 2001, 2002 and 2003, respectively, direct payments to the Corps, Bureau and Fish & Wildlife for operations and maintenance were included in the amount of (i) $117 million, $132 million and $129 million for the Corps, (ii) $55 million, $51 million and $54 million for the Bureau, and (iii) $13 million, $15 million and $15 million for Fish & Wildlife, respectively. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(8) Revenues Available For Other Purposes approximates the change in reserves from year to year. Reserves were $670 million at the end of fiscal year 1999 and $188 million at the end of fiscal year 2002.

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

$$\frac{\text{Total Operating Revenues-Operating Expense (Footnote 1)}}{\text{Non-Federal Project Debt Service}}$$

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

$$\frac{\text{Total Operating Revenues}}{\text{Operating Expense (Footnote 1) + Non-Federal Project Debt Service}}$$

Statement of Net Billing Obligations and Expenditures (1) (4)
(Actual Dollars in Thousands)

Fiscal years ending September 30,	2003	2002	2001
Operating Revenues from Publicly-Owned Utilities[2]	$ 1,723,138	$1,797,496	$ 939,362
Net Billing Obligations:			
Net Billing Credits	476,947	610,180	675,938
Payments in Lieu of Net Billing[3]	(140,261)	(111,329)	57,283
Net Billing Obligations — Cash	336,686	498,851	733,221
Net Billing Expenditures:			
Net Billed Debt Service	104,329	213,919	455,397
Other Entities O&M — Net Billed	208,535	167,026	208,839
Increase/(Decrease) in Prepaid Expense	23,822	117,906	68,985
Net Billing Expenditures — Accrual	$ 336,686	$ 498,851	$ 733,221

(1) Bonneville funds its obligation for net billed project costs on a cash basis and it expenses the net billed project budgets on an accrual basis. This reconciliation ties the cash net billing obligation to the accrual net billing obligation through the changes in Bonneville's prepaid expense.
(2) Bonneville's actual revenues from Publicly Owned Utilities exceeded net billing obligations. Most Publicly Owned Utilities are Participants in the Net Billed Projects.
(3) Includes voluntary direct cash payments made to Energy Northwest by Bonneville when the Participants' obligations to Energy Northwest exceed the allowed net billing credits.
(4) While the 2003 Bonds are not serviced by net billing, this table is provided to illustrate the extent of Bonneville's net billing obligations.

BONNEVILLE LITIGATION

Kaiser Aluminum Bankruptcy

Kaiser Aluminum and Chemical, Incorporated ("Kaiser"), a subsidiary of Kaiser Aluminum Corporation, is an aluminum company DSI customer of Bonneville's. On February 12, 2002, both Kaiser and its parent corporation Kaiser Aluminum Corporation filed for bankruptcy protection. Bonneville has a contract (the "Kaiser Contract") to sell Kaiser about 291 megawatts of electric power during the five-year period beginning October 1, 2001. Under an arrangement entered into after Kaiser and Bonneville executed the Kaiser Contract, Kaiser agreed to forgo most of such purchases, and Bonneville agreed to waive the obligation of Kaiser to make most of such purchases, through, but not beyond, October 2003. Consequently, since October 1, 2001, Kaiser has been purchasing only about 30 megawatts of power under the Kaiser Contract. Bonneville estimates that it has sold Kaiser between about $1 million and $2 million of power and related services for which Bonneville has not yet been paid. Such accounts receivable could be treated as unsecured, pre-petition debts of Kaiser in the bankruptcy proceeding and therefore Bonneville is uncertain whether such debts will be paid. Bonneville has recorded provisions for uncollectible amounts related to such accounts receivable.

In addition, Kaiser's purchase obligation under the Kaiser Contract is a "take-or-pay" obligation, meaning Kaiser must pay for the power if tendered by Bonneville, regardless of Kaiser's ability to accept delivery of the power for use at its facilities. The rate under which Kaiser is obligated to make such purchases is the Bonneville Industrial Firm Power (or "IP") Rate, which is currently about $34 per megawatt, subject to the various cost recovery rate adjustments described herein. The current IP Rate is above the current West Coast market prices for electric power. Due to these circumstances, Kaiser rejected the Kaiser Contract in the bankruptcy proceeding. The consequence of this rejection is that the "take or pay" obligation that Kaiser owes to Bonneville for future deliveries will be treated as a general unsecured claim.

The United States Department of Justice, acting on behalf of Bonneville, has filed a proof of claim in the amount of $78 million in this proceeding, reflecting the value of contracts Bonneville has with Kaiser.

PGET Bankruptcy

In July 2003, PG&E Energy Trading – Power L.P. ("PGET"), a non-utility power marketer and affiliate of PG&E, which in turn is a California utility, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Maryland. As a result, Bonneville has notified PGET that Bonneville has terminated all power sales and purchase transactions with PGET. Bonneville also notified PGET of Bonneville's calculation of a termination payment owed by PGET to Bonneville in the amount of approximately $24 million. Apart from relatively small dollar amounts relating to two short term power transactions, undelivered power by PGET, and accounts receivable owing to Bonneville at the time of filing, virtually all of the termination payment calculated by Bonneville is attributable to the mark-to-market value of a single 100 megawatt Augmentation Purchase by Bonneville. At the time of Bonneville's notification of termination, there were approximately three years' remaining performance under the Augmentation Purchase. Bonneville is unable to predict whether or the extent to which it will receive payment under the terminated transactions. Bonneville has referred the matter to the United States Department of Justice.

Longview Aluminum Bankruptcy

On January 28, 2003, Bonneville notified Longview Aluminum, LLC ("Longview") that Bonneville has terminated Longview's 280 average megawatt take-or-pay power sales contract because of nonpayment by Longview. Bonneville estimates that Longview is approximately $17 million in arrears in its payments under the contract and owes Bonneville approximately $3 million for accounts receivable and about $29 million for the forward value of the contract, which is based on the mark-to-market value of remaining sales as of the date of termination. Longview has asserted to Bonneville, and Bonneville disagrees, that the power sales contract entitles Longview to suspend its take-or-pay purchase obligation. Longview also has an unpaid $1.2 million payment obligation to Bonneville under a long-term transmission service agreement. In addition, Bonneville has made about $9 million in transmission investments, which Longview would be responsible to pay if it fails to meet its long-term transmission purchase obligation. Bonneville is evaluating potential actions to obtain payment. While Bonneville is not optimistic that it will receive full value for these contract obligations, Bonneville has not yet determined whether to take an accounting charge reflecting unrecoverable revenues in this matter.

In February 2003, Longview Aluminum filed two petitions for review against Bonneville in the Ninth Circuit Court. The first petition is a challenge to an invoice from Bonneville's Power Business Line for approximately $16 million. The second petition, with approximately $450,000 at issue, concerns invoices from Bonneville's Transmission Business Line. No legal theory was given as a basis for either suit, and the petitions did not request any relief.

On March 4, 2003, Longview filed for bankruptcy protection under the federal bankruptcy laws. Bonneville will seek payment for amounts owed it by Longview in the bankruptcy proceeding.

GNA Bankruptcy

On December 22, 2003, Golden Northwest Aluminum ("GNA"), a holding company that contracts on behalf of two DSIs, with Bonneville, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Oregon. Bonneville estimates GNA owes Bonneville approximately $15.8 million on an unsecured basis for breaching take-or-pay power purchase commitments in fiscal years 2002 and 2003. GNA has curtailed its load through June 2004, so its obligation to resume taking its contracted-for 236 megawatts of electric power from Bonneville will resume on July 1, 2004, absent further curtailment. If GNA elects to reject its remaining power purchase commitments with Bonneville, Bonneville would calculate its damages, if any, through the contract term, September 30, 2006.

Mirant Bankruptcy

On July 14, 2003, Mirant Americas Energy Trading, L.P. ("Mirant"), an independent power marketer and power trading counterparty of Bonneville's, filed a petition in the U.S. Bankruptcy Court for the Northern District of Texas. On July 30, 2003, Bonneville sent Mirant a letter terminating certain power purchases by Bonneville. The basis for this termination action was the filing of a bankruptcy petition, which is an event of default that permits the termination and close-out of existing positions between the parties.

Mirant contested Bonneville's right to terminate the contract, claiming that Bonneville was not a forward contract merchant under the U.S Bankruptcy Code, and therefore not entitled to terminate the contract upon filing of the bankruptcy by Mirant. Mirant filed a motion with the bankruptcy court seeking an order that by closing out its position, Bonneville violated the automatic stay provisions of the Bankruptcy Code, which provisions in most circumstances prohibit a party from obtaining recovery of obligations owed to it by the bankrupt without court consent.

The court issued an order on November 14, 2003, directing Bonneville to remedy its violations of the automatic stay by immediately taking all actions necessary to withdraw the termination letter, reinstate the terminated contracts and reinstate the parties to the status quo existing before the termination letter was sent. Thus, the effect of the order was that Bonneville was required to pay Mirant $522,014. Bonneville made this payment under protest and with a reservation of rights to appeal the decision. Other possible implications of the November 14, 2003 order are that Bonneville will not enjoy the safe-harbor provisions of the Code afforded to forward contract merchants. The order could further mean that upon a counter-party's bankruptcy, Bonneville will be precluded by the automatic stay from declaring a default, terminating extant agreements and liquidating all positions, the setoff of pre-petition mutual debts and claims, and to realize against any collateral held to secure the debtor's obligations under the confirmation agreements.

Benton County Litigation

On November 17, 2003, a group of Bonneville's Slice customers ("Benton Petitioners") filed a petition with the Ninth Circuit Court challenging Bonneville's final determinations of various adjustments and provisions under the Slice Agreements, including the Slice true-up adjustment charge. (The true-up charge is describe in "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Preference Customer Loads.") The Benton Petitioners assert that Bonneville's true-up adjustment charge and other determinations are inconsistent with the terms of the Slice contracts and that the Slice customers' audit of fiscal year 2002 charges revealed $83 million in charges that should have been made to other customers. The Benton Petitioners further assert that the court lacks jurisdiction to resolve the dispute because the Slice contracts require binding arbitration for such disputes. The Benton Petitioners have asked the court to determine whether it has jurisdiction over the dispute, and should the court determine that it does have jurisdiction, the Benton II Petitioners have requested the court to stay the case pending completion of arbitration, or in the alternative, to appoint a special master to make factual determinations in the case.

No schedule has been set for this case.

The Benton Petitioners have expressed an intention to intervene in the Northwest Requirements Utilities' Lawsuit, described below.

Northwest Requirements Utilities Lawsuit

On October 23, 2003, a group of Bonneville's full requirements Preference Customers, represented by the Northwest Requirements Utilities ("NRU"), a trade association, filed a petition in the Ninth Circuit Court challenging Bonneville's final determination of the true-up adjustment charge, final Slice rate and Slice revenue requirement for contract year 2002. Bonneville's final determination of the Slice true-up adjustment charge and the Slice revenue requirement under the Slice rate was made following a Slice customer audit which proposed a change in the Slice revenue requirement of approximately $83 million dollars. Bonneville's final determination agreed with some of the proposed changes but rejected other changes to the Slice revenue requirement for fiscal year 2002.

NRU's petition contests some of the adjustments Bonneville made to the Slice rate and Slice revenue requirement, based on the Slice rate methodology and the Slice customer audit for contract year 2002 of Bonneville's true-up adjustment. The petition also challenges the use of binding arbitration as a means to resolve a rate determination of Bonneville under the Northwest Power Act. This case has been consolidated with the Benton County Litigation case above. The court has entered an injunction against an arbitration proceeding on this matter and the briefing schedule has been vacated pending resolution of a motion to determine jurisdiction.

2002 Final Power Rates Challenge

Numerous Bonneville customers have filed petitions for review in the Ninth Circuit Court challenging Bonneville's 2002 Final Power Rates Proposal. The rates have been confirmed and approved by FERC. See " POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Strategy Contracts Opt-Out Provisions." A schedule set out by the Ninth Circuit Court calls for briefing to be completed this spring.

City of Burbank, California v. United States

In 1998, the City of Burbank, California ("Burbank") filed a breach of contract claim against the United States in the Court of Federal Claims. Burbank alleges that Bonneville breached a Power Sales and Exchange Agreement with Burbank by (i) converting the power delivery obligation under the agreement from a power sales mode to a power exchange mode and (ii) improperly calculating the power rate that Burbank is responsible to pay under the agreement. Burbank sought between $3 million and $4 million in damages.

Without motion of any party to the litigation, in July 2000, the Court of Federal Claims dismissed Burbank's action on the grounds that the matter is a dispute over a Bonneville rate and involves actions taken by Bonneville under its governing statutes. It was therefore determined that exclusive jurisdiction lies with the Ninth Circuit Court. In addition, on Bonneville's motion, the court found that Burbank failed to follow certain procedures required under the Contract Disputes Act. Burbank appealed the dismissal to the U.S. Court of Appeals for the Federal Circuit. The Court of Appeals reversed the Court of Federal Claims on the jurisdictional issue and remanded the Contract Disputes Act matter to the Court of Federal Claims.

As part of filing its claim under the Contract Disputes Act, Burbank, as well as the Cities of Glendale and Pasadena, submitted certified claims for improperly calculating the applicable power rate under their respective Power Sales and Exchange Agreements. In addition, the City of Burbank submitted a separate claim that alleges that Bonneville improperly converted the agreement from the sale mode to the exchange mode. Burbank's claim for improper calculation of the rate has increased from the original claim to approximately $9 million. The Glendale and Pasadena claims total $4 million and $2 million, respectively.

The claims filed by the cities under the Contract Disputes Act were denied by Bonneville's Contracting Officer, and in April 2003, the cities filed an appeal with the Department of Energy Contract Board of Appeals.

Residential Exchange Program Litigation

In connection with Subscription, Bonneville prepared certain *pro forma* Residential Purchase and Sales Agreements ("RPSAs") and tendered the form of such agreements to the Regional IOUs for their consideration and possible execution. The *pro forma* RPSAs proposed to define Bonneville's statutory obligations under the Residential Exchange Program provisions of the Northwest Power Act for the ten-year period beginning October 1, 2001. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line," "—Residential Exchange Program" and "—Power Marketing in the Period After Fiscal Year 2001."

During the same time-frame, Bonneville negotiated certain agreements (the "Residential Exchange Settlement Agreements") with Regional IOUs to settle Bonneville's statutory Residential Exchange Program obligation under such agreements in lieu of the RPSAs for the five- and/or ten-year period beginning October 1, 2001. In October 2000, all six Regional IOUs entered into the Residential Exchange Settlement Agreements in lieu of the RPSAs.

A number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the RPSAs and the Residential Exchange Settlement Agreements. A number of interventions have also been filed in the foregoing challenges. Among those participating in the litigation are a group of DSIs, all six Regional IOUs and a number of Preference Customers and Preference Customer groups.

The petitions for review do not specify the precise nature of the challenges to Bonneville's final actions with regard to the RPSAs and the Residential Exchange Settlement Agreements, but allege generally that the RPSAs and Residential Exchange Settlement Agreements violate the Bonneville Project Act, the Pacific Northwest Consumer Power Preference Act, the Transmission System Act, the Northwest Power Act, NEPA, and/or the Administrative Procedure Act. Bonneville expects the likely remedies sought would be that the Residential Exchange Settlement Agreements, and/or RPSAs, be remanded to Bonneville for redevelopment or that Regional IOUs be allowed only to participate in the Residential Exchange Program under the RPSAs.

In October 2003, Bonneville and members of the two major utility groups in the region signed a conditional settlement of the foregoing litigation, which if effected, would have reduced Bonneville's Subscription power rates for public utilities and DSIs by 7.4 percent below fiscal year 2003 average rates. The settlement required the approval of numerous Preference Customers by a specified date and the necessary approvals were not obtained. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates." As a result of the lack of settlement, a briefing schedule has been established in the cases involving challenges to the Residential Exchange Settlement Agreements.

Pacific Northwest Generating Cooperative v. Bonneville Power Administration

In April 2000, Bonneville issued a document entitled "Power Subscription Strategy—Administrator's Supplemental Record of Decision" ("Supplemental Subscription Strategy ROD"). The Supplemental Subscription Strategy ROD was issued to address issues and developments that had occurred since Bonneville issued its original Subscription Strategy Record of Decision in December 1998. The Subscription Strategy Record of Decision, and the Supplemental Subscription Strategy ROD set the course for Bonneville to establish rates and offer power sales contracts upon expiration of previously existing contracts on September 30, 2001.

Shortly after issuance of the Supplemental Subscription Strategy ROD, Bonneville was sued in the Ninth Circuit Court by Vanalco, Inc. (a DSI), and the Pacific Northwest Generating Cooperative ("PNGC") and its members. The PNGC is a consortium of generating cooperative Preference Customers in the Pacific Northwest. Petitioner Vanalco has voluntarily withdrawn from the litigation. In an order dated January 23, 2001, the court vacated the existing briefing schedule and the case was selected for inclusion in the Ninth Circuit Court's mediation program. The case has been stayed.

In a related matter, Puget Sound Energy, Inc. filed a petition for review in January 2001 challenging "Slice of the System" contracts executed between Bonneville and certain public utility customers. Puget alleges the contracts violate Bonneville's statutory authorities. The case was selected for inclusion in the Ninth Circuit Court's mediation program, and has been stayed.

National Wildlife Federation v. U.S. Army Corps of Engineers

In a lawsuit filed in March 1999 in the United States District Court for the District of Oregon, the National Wildlife Federation ("NWF"), an advocate for environmental causes, has asked the court (1) to find that the Corps has violated state water quality standards for dissolved gas and temperature at four Federal System dams in the lower Snake River and (2) to order the Corps to present to the court a plan for meeting the standards. Plaintiffs seek a court order that would require the Corps to take immediate actions to meet state water quality standards.

Among the measures that plaintiffs assert would reduce gas are a number of capital improvements such as installation of stilling basins and dividers between spillways. Examples of measures to control water temperatures include boring additional channels in a dam so that a dam could pass water from varying depths in the dam's reservoir, and draining reservoirs behind the dams so that the river, although smaller in volume, flows more quickly.

In February 2001, the court issued an opinion and order granting summary judgment in favor of the NWF. The court found that the Corps did not adequately address compliance with its legal obligations under the Clean Water Act in the Corps' 1998 record of decision on dam operations under biological opinions, and supplements thereto, then in effect under the ESA. For a discussion of biological opinions affecting the Federal System hydroelectric projects, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife." The court ordered the Corps to issue a new decision by the latter part of April 2001 to replace the Corps' 1998 record of decision and to address compliance with the Clean Water Act in the new decision.

In May 2001, the Corps filed a new Record of Consultation and Statement of Decision ("ROCASOD") with the court. As expressed in the ROCASOD, the Corps agreed to consider additional measures in future years to improve water quality. In August 2001, plaintiffs filed an amended complaint challenging the adequacy of the new ROCASOD. Plaintiff's motion included a request for injunctive relief, in addition to a request for remand of the amended ROCASOD to the Corps. The Corps has informed Bonneville that the request for injunctive relief, if successful, could lead to increased funding or program requirements to meet state water quality standards. In November 2002, the district court heard oral arguments on summary judgment motions from plaintiffs and defendants. In January 2003, the court upheld the Corp's ROCASOD and ruled in favor of the Corps on the motions for summary judgment. In March 2003, plaintiffs appealed the court's January ruling upholding the Corps' ROCASOD.

Alturas Transmission Dispute

In the mid-1990's Bonneville participated in the interconnection ("Alturas Interconnection") of its federal transmission facilities with facilities owned and operated by Sierra Pacific Power Co. ("Sierra Pacific"). In 1998, Sierra Pacific sought approval from FERC for the Alturas Interconnection, which FERC granted. In late 1998, Sierra Pacific filed at FERC an operating agreement for the interconnection. The Transmission Agency of Northern California ("TANC") and other California public and private utilities intervened in the proceeding, asserting that the interconnection adversely affected reliability of the Pacific Northwest-Southwest AC Intertie, and FERC set the matter for hearing. In March 2001, the Presiding Administrative Law Judge ("ALJ") issued an Initial Decision that supports Bonneville's position that there is no adverse impact on reliability of the Pacific Northwest-Southwest AC Intertie, although the ALJ limited any potential expansion of the Alturas Intertie. Many parties, including Bonneville, appealed the ALJ's decision. Bonneville objected to the limits on expansion, but supported other aspects of the Initial Decision. On August 25, 2003, FERC issued an opinion that modified the Initial Decision by removing the limit on expansion, but affirmed the decision in other respects. TANC and Sacramento Utility District ("SMUD") filed a request for rehearing of the FERC decision and in February, 2004 FERC issued on an opinion denying rehearing and affirming its August 2003 decision. TANC and SMUD may appeal the FERC decision to a federal appellate court.

Confederated Tribes of the Umatilla Indian Reservation and the Nez Perce Tribe, *et. al.* v. Bonneville Power Administration

In November 2001, the Sierra Club and other environmental organizations petitioned the Ninth Circuit Court to review Bonneville's decision document of August 2001 that sets forth certain aspects of the implementation of the 2000 Biological Opinion and compliance with other laws. See "—Power Business Line—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—2000 Biological Opinion." A similar petition was filed by the Confederated Tribes of the Umatilla Indian Reservation and the Nez Perce Tribe. The court has consolidated these petitions. Among other things, the challenged decision document provides guidance for operating the Federal System hydroelectric dams in a manner intended to protect listed fish species under the ESA. The decision document also provides certain exceptions to such operations in the event power generation is needed to address emergency electric system needs.

Petitioners allege that Bonneville's decision document does not comply with provisions of the Northwest Power Act directing Bonneville to exercise its fish and wildlife responsibilities in a manner that provides "equitable treatment" for fish and wildlife with other purposes for which the Federal System facilities are managed and operated. Petitioners seek to vacate the decision document and remand it to Bonneville to make it comply with the Northwest

Power Act and other applicable law. On September 2, 2003, the court issued an opinion in the case affirming Bonneville's decisions and rejecting all claims of the petitioners.

Blachly-Lane Electric Cooperative, *et al*. v. Bonneville Power Administration

A consortium of publicly-owned utilities, municipalities and cooperatives filed a petition for review in the Ninth Circuit Court in September 2001. The petitioners allege that in a Record of Decision dated June 20, 2001, Bonneville decided to sell more power than is available from the Federal Base System resources, including sales to DSIs, resulting in a shift of an estimated $550 million per year in power costs to Bonneville's Preference Customers. The petitioners allege that Bonneville's actions violated public preference provisions of the Northwest Power Act. On October 30, 2003, the court issued an unpublished opinion, rejecting the claims of the petitioners and denying the petition for review.

Southern California Edison v. Bonneville Power Administration

Southern California Edison ("SCE") has three separate outstanding petitions for review against Bonneville in the Ninth Circuit Court. The cases all challenge actions taken by Bonneville regarding the implementation of a 1988 power sales contract between Bonneville and SCE.

In the first petition for review, SCE challenged Bonneville'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. In the second petition for review, SCE challenged a Record of Decision issued by Bonneville in a rate adjustment proceeding. That proceeding (FPS-96R) amended Bonneville's FPS-96 rate schedule to establish a posted rate for a capacity product SCE may purchase as part of an option feature of the Sale and Exchange Agreement. SCE alleges that the rate adjustment violates its power sales contract. In the third petition for review, SCE challenged Bonneville's letter to Southern terminating service under its power sales contract due to SCE's nonperformance. All three petitions for review were dismissed by the Ninth Circuit Court for lack of jurisdiction and were transferred to the U.S. Court of Federal Claims. Subsequently, the cases were dismissed by the U.S. Court of Federal Claims and SCE has filed administrative claims for relief with Bonneville.

The current status of the claims is as follows:

Conversion from Sale to Exchange mode. Rather than await a Contracting Officer's Decision, SCE filed an action in the Court of Federal Claims on December 26, 2002, based on its assertion that the claim should be "deemed denied" by Bonneville. SCE's complaint seeks damages in the amount of approximately $200,000,000. Bonneville filed a motion to dismiss for failure to state a claim for which relief can be granted. On October 24, 2003 the motion was denied.

Challenge to FPS-96R. Bonneville notified SCE that the claim was a challenge to Bonneville's rates, and such challenges are cognizable only in the Ninth Circuit Court of Appeals. Thus far, SCE has not responded. SCE has missed the ninety day deadline for filing in the Ninth Circuit, but could still attempt to file in the Court of Federal Claims.

Termination for Default. In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. SCE has filed an administrative claim with Bonneville under the Contract Disputes Act. SCE seeks damages in the amount of $20,000,000.

Kevin Bell, *et al.* v. Bonneville Power Administration

Two petitions for review were filed in the Ninth Circuit Court challenging Bonneville's decisions to execute certain agreements with most of Bonneville's DSIs. These agreements are generally called load reduction or curtailment agreements. The agreements were executed in 2001 to enable Bonneville to reduce its obligations to serve power to these customers, and to buy power back from these customers at below market prices at a time when market prices for power were extremely high. Petitioners allege that Bonneville exceeded its statutory authority and violated ratemaking and resource acquisition provisions of the Northwest Power Act, as well as the National Environmental Policy Act.

In August 2003, the Ninth Circuit Court issued an opinion affirming Bonneville's actions, denying the petition for review and rejecting all of petitioners' arguments.

Industrial Customers of Northwest Utilities, et al. v. Bonneville Power Administration

Three petitions for review were filed in the Ninth Circuit Court challenging Bonneville's February 2003 determination that the criteria for triggering a Safety Net Cost Recovery Clause (SN-CRAC) had been satisfied. The consequence of triggering the SN-CRAC was to initiate a proceeding to revise Bonneville's rates. The three petitions were filed by an entity representing industrial customers of Northwest utilities, by Alcoa, Inc. (a DSI), and by some of Bonneville's public utility customers. Numerous other parties have moved to intervene. On June 12, 2003 the court consolidated all three petitions for review. On August 15, 2003, Bonneville filed a motion to dismiss these cases for lack of jurisdiction, or in the alternative, to stay the cases pending completion of an administrative review process at FERC. Bonneville's motion was referred to the merits panel, and briefs on the merits have been filed.

In addition, Industrial Customers of Northwest Utilities have filed a separate related petition for review in the Ninth Circuit Court challenging Bonneville's SN-CRAC Record of Decision. A motion to dismiss the petition for lack of jurisdiction is pending before the court.

Yakama Nation Litigation

On June 24, 2003 the Yakama Nation, a tribal entity, filed a petition for review in the Ninth Circuit Court challenging a letter issued by Bonneville dated March 28, 2003. The letter addresses Bonneville's funding of measures in the Council's Fish and Wildlife Program. The petition does not provide any information regarding the Yakama Nation's legal theories and includes no request for expedited review or injunctive relief. The case has been selected for inclusion in the Ninth Circuit Court's mediation program and the parties are currently in settlement discussions.

Upper Columbia United Tribes Litigation

On December 18, 2003, the Upper Columbia United Tribes (UCUT), as well as certain other tribal petitioners, filed a petition for review in the Ninth Circuit Court challenging a letter from Bonneville to the Council. As with the Yakama Nation Litigation, above, the challenged letter addresses issues related to Bonneville's Fish and Wildlife Funding. The UCUT litigation is related to the Yakama Nation litigation, above, and is being considered for inclusion in the Ninth Circuit Court's mediation program.

ESA Litigation

National Wildlife Federation v. National Marine Fisheries Service

In a lawsuit filed May 4, 2001, in the United States District Court for the District of Oregon, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Biological Opinion and incidental take statement are arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NMFS (now known as NOAA Fisheries) to reinitiate consultation with the action agencies responsible for operation of the Federal System hydroelectric projects—the Corps, the Bureau, and Bonneville—and to prepare a new biological opinion. Plaintiffs subsequently filed a First Amended Complaint, and the action agencies filed their answer. Several entities have intervened in this lawsuit. The court heard oral argument on motions for summary judgment in April 2003.

In early May 2003, the U.S. District Court judge issued a decision on the adequacy of the 2000 Biological Opinion. The ruling provides that the 2000 Biological Opinion is inadequate because it relies on offsite mitigation measures that are "not reasonably certain to occur."

In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. The court's order gives NOAA Fisheries until early June 2004 to reconsider the biological opinion. In an additional ruling in late June 2003, the court agreed to permit the 2000 Biological Opinion to remain in effect on an interim basis for up to one year (until early June 2004) while the 2000 Biological Opinion is on remand to NOAA Fisheries.

To address the court's concerns, it is possible that a revised biological opinion may increase the forms and extent of mitigation measures beyond those required in the 2000 Biological Opinion as reviewed by the court. If NOAA Fisheries were to include additional or expanded measures in a new or amended biological opinion it is possible that substantial additional costs could be borne by Bonneville.

There is currently before the court a motion to define the geographic areas that actions to be taken under the Biological Opinion should address.

Alsea Valley Alliance v. Evans

In September 2001, the United States District Court for the District of Oregon issued an order finding that NMFS (now known as NOAA Fisheries) had exceeded its authority by listing only the wild-salmon portion of the Oregon Coast Coho salmon as endangered or threatened. The court found that because NOAA Fisheries did not include the entire "distinct population segment" which also includes hatchery fish, it acted arbitrarily and capriciously. As a result, the court de-listed the Oregon Coast Coho salmon as endangered or threatened.

After this decision, a number of intervener environmental groups appealed the decision to the Ninth Circuit Court. These groups successfully stayed the findings of the district court. The effect of the stay is to temporarily re-list the Oregon Coast Coho pending the decision on appeal. NOAA Fisheries has not yet officially proposed its amended Hatchery Listing Policy, and the parties await a ruling on the appeal from the Ninth Circuit Court.

In addition to the appeal, NOAA Fisheries received 14 additional petitions from various interest groups to de-list other salmon populations. As a result, NOAA Fisheries has decided to revisit its Hatchery Listing Policy. The parties that filed petitions to de-list other salmon populations have agreed to address issues and make a decision regarding the various pending salmon "distinct population segments" in spring 2004.

Spill Reduction Litigation

In February 2004, two environmental groups delivered a formal "intent to sue" notice to Bonneville, the Corps and the Bureau. The notice, a prerequisite to filing suit under the ESA, is in response to Bonneville's proposal for a reduction in summer spill at four federal dams. The notice indicates that the environmental groups will file suit against the above listed agencies unless alleged ESA violations are cured within sixty days. NOAA Fisheries, one of the key decision makers in this matter, is expected to make a recommendation about the spill program in April 2004. While Bonneville's spill proposal would increase power generation at the four dams, Bonneville's power rates and financial forecast do not assume any positive effects from the proposed reduction in summer spill.

Rates Litigation

Bonneville's rates are frequently the subject of litigation. 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. Bonneville proposed new power rates for the five years beginning October 1, 2002, which were subsequently approved by FERC in July 2003. Bonneville has also proposed an SN-CRAC rate level adjustment, which is under review by FERC. Bonneville has proposed transmission rates for the two years beginning October 1, 2003. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001," "TRANSMISSION BUSINESS LINE—Bonneville's Transmission and Ancillary Services Rates" and "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates."

It is the opinion of Bonneville's General Counsel that if any rate were to be rejected, 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; provided, however, that in the case of a FERC-ordered transmission rate no such rate shall be unjust, unreasonable or unduly discriminatory. Thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Miscellaneous Litigation

From time to time, Bonneville is involved in numerous other cases and arbitration proceedings, including land, contract, employment, 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.

(THIS PAGE INTENTIONALLY LEFT BLANK)

APPENDIX B-1

FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS
FOR THE YEARS ENDED SEPTEMBER 30, 2003 AND 2002

(THIS PAGE INTENTIONALLY LEFT BLANK)

PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying balance sheets and the related statements of changes in capitalization and long-term liabilities, of revenues and expenses, and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2003 and 2002, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2003, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2003, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The Schedule of Amount and Allocation of Plant Investment as of September 30, 2003 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2003 (Schedule B) are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
November 7, 2003

Financial Statements

Statements of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2003	2002	2001
Operating Revenues			
Sales	**$3,328,277**	$3,407,404	$3,563,182
SFAS 133 mark-to-market	**55,265**	38,354	47,877
Miscellaneous Revenues	**53,678**	49,571	66,902
U.S. Treasury Credits for Fish	**174,884**	38,400	600,708
Total operating revenues	**3,612,104**	3,533,729	4,278,669
Operating Expenses			
Operations and maintenance	**1,198,521**	1,319,707	1,023,180
Purchased power	**1,043,009**	1,286,867	2,296,076
Nonfederal projects	**119,534**	230,175	473,100
Federal projects depreciation	**350,025**	335,205	323,314
Total operating expenses	**2,711,089**	3,171,954	4,115,670
Net operating revenues	**901,015**	361,775	162,999
Interest Expense			
Interest on federal investment:			
Appropriated funds	**212,391**	258,195	248,429
Long-term debt	**166,598**	151,997	129,159
Allowance for funds used during construction	**(33,398)**	(57,892)	(45,679)
Net interest expense	**345,591**	352,300	331,909
Net revenues (expenses) before cumulative effect of SFAS 133	**555,424**	9,475	(168,910)
Cumulative effect of SFAS 133	—	—	(168,491)
Net Revenues (Expenses)	**555,424**	9,475	(337,401)
Accumulated net (expenses) revenues, Oct. 1	**(211,676)**	(221,151)	132,810
Irrigation Assistance	—	—	(16,560)
Accumulated net revenues (expenses), Sept. 30	**$ 343,748**	$(211,676)	$(221,151)

The accompanying notes are an integral part of these statements.

Balance Sheets

Federal Columbia River Power System
As of Sept. 30 — thousands of dollars

Assets

	2003	2002
Utility Plant		
Completed plant	**$11,873,798**	$ 11,488,047
Accumulated depreciation	**(4,281,060)**	(4,052,117)
	7,592,738	7,435,930
Construction work in progress	**1,308,624**	1,200,179
Net utility plant	**8,901,362**	8,636,109
Nonfederal Projects		
Conservation	**47,246**	47,733
Hydro	**146,210**	167,080
Nuclear	**2,181,182**	2,127,907
Terminated hydro facilities	**28,840**	29,555
Terminated nuclear facilities	**3,883,115**	3,829,269
Total nonfederal projects	**6,286,593**	6,201,544
Decommissioning Cost	**126,000**	73,861
Conservation, net of accumulated amortization of $892,218 in 2003 and $831,631 in 2002	**374,443**	409,571
Fish and Wildlife, net of accumulated amortization of $133,743 in 2003 and $129,207 in 2002	**128,337**	134,204
Current Assets		
Cash	**503,026**	235,409
Accounts receivable, net of allowance	**146,768**	206,036
Accrued unbilled revenues	**190,416**	93,004
Materials and supplies, at average cost	**84,306**	85,107
Prepaid expenses	**288,068**	285,696
Total current assets	**1,212,584**	905,252
Other Assets	**230,756**	151,458
	$17,260,075	$ 16,511,999

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2003	2002
Capitalization and Long-Term Liabilities		
Accumulated net revenues (expenses)	**$ 343,748**	$ (211,676)
Federal appropriations	**4,607,476**	4,595,915
Capitalization adjustment	**2,124,697**	2,192,400
Long-term debt	**2,521,554**	2,563,141
Nonfederal projects debt	**6,045,931**	5,958,538
Decommissioning reserve	**126,000**	73,861
Total capitalization and long-term liabilities	**15,769,406**	15,172,179
Commitments and Contingencies (Notes 5 and 6)		
Current Liabilities		
Current portion of federal appropriations	**73,484**	46,687
Current portion of long-term debt	**176,200**	207,300
Current portion of nonfederal projects debt	**240,662**	243,006
Accounts payable and other current liabilities	**369,821**	343,425
Total current liabilities	**860,167**	840,418
Deferred Credits	**630,502**	499,402
	$17,260,075	$16,511,999

Statements of Changes in Capitalization and Long-Term Liabilities

Federal Columbia River Power System
Including current portions — thousands of dollars

	Accumulated Net (Expenses) Revenues	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2001	$ (221,151)	$ 4,670,930	$ 2,688,542	$ 6,171,949	$ 2,328,977	$15,639,247
Increase in federal appropriations for construction	—	168,583	—	—	—	168,583
Repayment of federal appropriations for construction	—	(196,911)	—	—	—	(196,911)
Capitalization adjustment amortization	—	—	—	—	(67,356)	(67,356)
Increase in long-term debt	—	—	390,000	—	—	390,000
Repayment of long-term debt	—	—	(308,101)	—	—	(308,101)
Net increase in nonfederal projects debt	—	—	—	258,775	—	258,775
Repayment of nonfederal projects debt	—	—	—	(229,180)	—	(229,180)
Decommissioning reserve	—	—	—	—	4,640	4,640
Net revenues	9,475	—	—	—	—	9,475
Balance at Sept. 30, 2002	$ (211,676)	$ 4,642,602	$ 2,770,441	$ 6,201,544	$ 2,266,261	$15,669,172
Increase in federal appropriations for construction	**—**	**99,418**	**—**	**—**	**—**	**99,418**
Repayment of federal appropriations for construction	**—**	**(61,060)**	**—**	**—**	**—**	**(61,060)**
Capitalization adjustment amortization	**—**	**—**	**—**	**—**	**(67,703)**	**(67,703)**
Increase in long-term debt	**—**	**—**	**470,000**	**—**	**—**	**470,000**
Repayment of long-term debt	**—**	**—**	**(482,687)**	**—**	**—**	**(482,687)**
Refinance of long-term debt	**—**	**—**	**(60,000)**	**—**	**—**	**(60,000)**
Net increase in nonfederal projects debt	**—**	**—**	**—**	**99,288**	**—**	**99,288**
Repayment of nonfederal projects debt	**—**	**—**	**—**	**(14,239)**	**—**	**(14,239)**
Decommissioning reserve	**—**	**—**	**—**	**—**	**52,139**	**52,139**
Net revenues	**555,424**	**—**	**—**	**—**	**—**	**555,424**
Balance at Sept. 30, 2003	**$ 343,748**	**$ 4,680,960**	**$ 2,697,754**	**$ 6,286,593**	**$ 2,250,697**	**$16,259,752**

The accompanying notes are an integral part of these statements.

Statements of Cash Flows

Federal Columbia River Power System
For the years ended Sept. 30 — thousands of dollars

	2003	2002	2001
Cash from Operating Activities			
Net revenues (expenses)	**$ 555,424**	$ 9,475	$ (337,401)
Expenses (income) not requiring cash:			
Depreciation	**269,957**	254,332	247,247
Amortization of conservation and fish and wildlife	**80,068**	78,047	76,067
Amortization of capitalization adjustment	**(67,703)**	(67,356)	(68,784)
AFUDC	**(33,398)**	(57,892)	(45,679)
(Increase) decrease in:			
Receivables and unbilled revenues	**(38,144)**	88,765	(31,283)
Materials and supplies	**801**	115	(20,930)
Prepaid expenses	**(2,372)**	(98,547)	(101,254)
Increase (decrease) in:			
Accounts payable and other current liabilities	**26,396**	(167,532)	138,687
IOU Settlement	**55,488**	—	—
Other	**(3,686)**	(6,399)	114,060
Cash provided by (used for) operating activities	**842,831**	33,008	(29,270)
Cash from Investment Activities			
Investment in:			
Utility plant	**(501,813)**	(487,030)	(399,220)
Conservation	**(25,458)**	(25,344)	141
Fish and wildlife	**(11,156)**	(6,102)	(16,493)
Other	**(2,458)**	—	—
Cash used for investment activities	**(540,885)**	(518,476)	(415,572)
Cash from Borrowing and Appropriations			
Increase in federal constructions appropriations	**99,418**	168,583	230,388
Repayment of federal construction appropriations	**(61,060)**	(196,911)	(125,469)
Irrigation assistance	—	—	(16,560)
Increase in long-term debt	**470,000**	390,000	260,000
Repayment of long-term debt	**(482,687)**	(308,101)	(84,658)
Refinance of long-term debt	**(60,000)**	—	—
Cash (used for) provided by borrowing and appropriations	**(34,329)**	53,571	263,701
Increase (Decrease) in cash	**267,617**	(431,897)	(181,141)
Beginning cash balance	**235,409**	667,306	848,447
Ending cash balance	**$ 503,026**	$ 235,409	$ 667,306

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of General Accounting Policies

Principles of Combination

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), which purchases, transmits and markets power, and the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) for which BPA is the power marketing agency. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. The costs of multipurpose Corps and Reclamation projects are assigned to specific purposes through a cost allocation process. Only the portion of total project costs allocated to power is included in these statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect specific legislation and executive directives issued by U.S. government departments. (BPA is a unit of the Department of Energy; Reclamation is part of the Department of the Interior; and the Corps is part of the Department of Defense.) FCRPS properties and income are tax-exempt. All material intercompany accounts and transactions have been eliminated from the combined financial statements.

Management Estimates

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

Reclassifications

Certain reclassifications were made to the 2001 and 2002 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2003. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's power and transmission rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the National Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power, for nonfirm energy sold within the region, and for transmission service. Statutory standards include a requirement that these rates be sufficient to assure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs.

After final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit. Action seeking such review must be filed within 90 days of the final FERC decision. The court of appeals may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's general counsel that, if a rate were rejected, it would be remanded to BPA for reformulation.

BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every 6 months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of modified accumulated net revenues is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor. Some of these rate adjustment clauses are calculated initially on forward-looking estimates of market conditions, and adjustments are made after the fact when actual conditions are known. These adjustments result in an additional charge or rebate due customers for any excess or shortfall of amounts initially charged to them.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46 percent for the first half of fiscal 2002 compared to base rates, and 41 percent for the second half of fiscal 2002. The LB CRAC percentage increase was again revised to approximately 32 percent and 39 percent, respectively, for the 6-month periods beginning Oct. 1, 2002 and April 1, 2003.

On Sept. 30, 2003, BPA recognized a receivable of $4.6 million for the LB CRAC period ended March 31, 2003, and BPA estimated a receivable of zero for the LB CRAC period ended Sept. 30, 2003. On Sept. 30, 2002, BPA recognized a liability of $5.8 million for the LB CRAC period ended March 31, 2002, and a receivable of $2.3 million for the LB CRAC period ended Sept. 30, 2002. The August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a one-year rate increase beginning Oct. 1, 2002, of approximately 11 percent for most of the requirements rates on top of the revised levels of the LB CRAC. The SN CRAC did not trigger in fiscal 2002 but did trigger in fiscal 2003, requiring an expedited rate case and resulting in rates that went into effect Oct. 1, 2003. BPA received interim approval of its recent SN CRAC rate proposal on Oct. 1, 2003, 105 FERC 61,006 (2003).

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percentage of BPA's power costs in exchange for a fixed percentage of generation and capabilities. Settlement of any over or under collection occurs in the subsequent year. For the fiscal 2003 settlement, BPA recognized a $30.4 million liability to be paid in fiscal 2004. For the fiscal 2002 settlement, BPA recognized a receivable of $49 million which was received in fiscal 2003.

FERC granted final approval for BPA's Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA separately submitted a Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on Oct. 11, 2001, FERC granted final approval for corrections to the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001) and granted final approval on July 21, 2003, 104, FERC 61,093 (2003).

Because of the regulatory environment in which BPA establishes rates, certain costs may be deferred and expensed in future periods under Statement of Financial Accounting Standards (SFAS 71), Accounting for the Effects of Certain Types of Regulation.

SFAS 71 *Assets*

In order to defer incurred costs under SFAS 71, a regulated entity must have the statutory authority to establish rates that recover all costs and rates so established must be charged to and collected from customers. Due to increasing competitive pressures, BPA may be required to seek alternative solutions in the future to avoid raising rates to a level that is no longer competitive. If BPA's rates should become market-based, SFAS 71 would no longer be applicable, and any costs deferred under that standard would be expensed in the Statement of Revenues and Expenses.

The SFAS 71 assets of $4.7 billion, shown in the table on page 34, reflect an increase of $138 million from the prior year. Amortization of these costs aggregating $84 million in 2003, $299 million in 2002 and $259 million in 2001 is reflected in the Statements of Revenues and Expenses. If BPA were to discontinue using SFAS 71 it would simultaneously write down the SFAS 71 assets and amortize the remaining Appropriations Capitalization Adjustment resulting in a $2.6 billion net extraordinary loss being reported in the Statement of Revenues and Expenses.

Utility Plant

Utility plant is stated at original cost. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. The costs of additions, major replacements

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2003	2002
Nonfederal projects:		
Conservation	$ 47,246	$ 47,733
Terminated hydro facilities	28,840	29,555
Terminated nuclear facilities	3,883,115	3,829,269
Decommissioning cost	126,000	73,861
Conservation	374,443	409,571
Fish and wildlife	128,337	134,204
Settlements	105,313	17,594
Additional retirement contributions	23,400	36,800
	$ 4,716,694	$ 4,578,587

and betterments are capitalized. Repairs and minor replacements are charged to operating expense. In accordance with FERC requirements the cost of utility plant retired, together with removal costs less salvage, is charged to accumulated depreciation when it is removed from service.

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 10 to 20 years for conservation and 15 years for fish and wildlife.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) constitutes interest on the funds used for utility plant under construction. AFUDC is capitalized as part of the cost of utility plant and results in a non-cash reduction of interest expense. While cash is not realized currently from this allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from higher plant in-service and higher depreciation expenses. AFUDC is based on the monthly construction work in progress (CWIP) balance. A portion of CWIP as stated on the balance sheets represents study and investigation costs to which AFUDC is not attributed.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects (1.8 percent to 6.3 percent in 2003, 3.3 percent to 6.5 percent in 2002 and 2.5 percent to 6.6 percent in 2001). Capitalization rates for other construction were approximately 6.3 percent in 2003, 6.5 percent in 2002 and 6.6 percent in 2001. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

BPA adopted SFAS 143, Accounting for Asset Retirement Obligations, on Oct. 1, 2002. SFAS 143 requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as a liability. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows.

Regulation

Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense allowed in rates. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset under SFAS 71. BPA expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation.

Also through regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2003, BPA has an estimated $146 million regulatory liability for these removal costs recorded in Accumulated Depreciation.

Asset Retirement Obligations Activity

Upon adoption of SFAS 143, BPA recorded an ARO for WNP-1 and Columbia Generating Station (See Decommissioning and Restoration Costs in Note 5, Commitments and Contingencies) for $72.1 million and adjusted the ARO for the Trojan plant to $57.8 million. Prior to the adoption of SFAS 143, the ARO associated with the Trojan plant was recorded on a nominal dollar basis at the time of its abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. With the adoption of SFAS 143, the regulatory asset (Decommissioning Cost) and the related ARO (Decommissioning Reserve) for the Trojan plant were reduced by $16.1 million to adjust the balances to an estimated fair value as required by SFAS 143. As of Sept. 30, 2003, the ARO for WNP-1, Columbia Generating Station and Trojan are $126 million. A corresponding amount representing a regulatory asset is included within Decommissioning Costs in the Balance Sheet.

The adoption of SFAS 143 did not result in a cumulative effect adjustment on the Statement of Revenue and Expenses as the effect was offset by a regulatory asset. $89.9 million has already been funded by BPA and held in trust relating to these AROs. The remaining amount will be collected in future rates.

The following presents the proforma effects to the balances and activities in AROs for the accounting periods reported herein had SFAS 143 been in effect for all periods:

Asset Retirement Obligations Activity

As of Sept. 30 — thousands of dollars

	Proforma 2003	Proforma 2002
Beginning Balance	$129,900	$134,100
Activity:		
Expenditures	(7,000)	(9,100)
Accretion	3,100	3,100
Revisions	—	1,800
Ending Balance	$126,000	$129,900

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and the Corps. Cash paid for interest was $466 million in 2003, $484 million in 2002 and $464 million in 2001.

Non-cash transactions include changes in non-federal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $99 million in 2003, $259 million in 2002 and $61 million in 2001.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist of available-for-sale investments held by Energy Northwest and BPA accounts receivable. Energy Northwest invests exclusively in U.S. government securities and agencies. BPA's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased capacity, energy, or other products and services. These customers are generally large and stable and do not represent a significant concentration of credit risk.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of the company.

In conjunction with the financial reviews, BPA often obtains credit support in the form of parental guarantees and letters of credit to support established credit limits.

BPA also utilizes netting agreements and prepayment agreements to mitigate the credit risk of financial instruments.

Credit Risk from California

California power markets had been in turmoil several years ago, having experienced historically high power prices and volatility along with the continued uncertainty related to deregulation. Defaults by Pacific Gas & Electric (which filed for bankruptcy protection in April 2001) and Southern California Edison (which has established a creditor payment plan) in payments for energy and transmission to the California Independent System Operator (Cal-ISO) resulted in the Cal-ISO not paying its suppliers. In addition, the California Power Exchange (Cal-PX) has substantial outstanding payment obligations due from the California investor-owned utilities for day-ahead power exchanges. The Cal-PX filed for bankruptcy protection in March 2001.

BPA entered into certain power sales during the fiscal year 2001 through the Cal-PX for which BPA has not yet been paid. In addition BPA sold power and related services to the Cal-ISO during fiscal year 2001 for which BPA has not yet been paid in full. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, BPA has recorded provisions for uncollectible receivables and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, BPA is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

Retirement Benefits

FCRPS employees belong to either the Civil Service Retirement System (CSRS) or the Federal Employees' Retirement System (FERS). FCRPS and its employees contribute to the systems. Based on the statutory contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is variable based upon options chosen by the participant but does not exceed 24.2 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

Beginning in fiscal 1998, and for the remainder of the rate period ended in 2001, FCRPS agreed to contribute additional amounts as a result of an underfunded status of the CSRS. These amounts have been calculated based on an estimate of FCRPS employees who participate in the plan as well as an estimate of FCRPS' share of the underfunded status. These contributions are projected over a period of years as shown in the table. The payments, when made, will be directly to the U.S. Treasury.

BPA paid $35.1 million, $55.2 million and $8.0 million to the U.S. Treasury during 2003, 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $23.4 million as of Sept. 30, 2003, which represents the additional deferred contribution for 1998 through 2003. This amount has been recorded as an SFAS 71 asset on the Balance Sheet for recovery of the costs through rates in the period beginning Oct. 1, 2001. The related liability is included in other current liabilities and deferred credits in the accompanying Balance Sheet. At Sept. 30, 2003, BPA has scheduled additional payments totaling $119.7 million as follows.

Scheduled Additional CSRS Contributions

thousands of dollars

Scheduled Contributions	
2004	$ 30,900
2005	26,500
2006	23,200
2007	21,100
2008	18,000
	$119,700

BPA expects to recognize these amounts as expense in the years in which they are specifically recovered through rates.

Deferred Credits

Deferred credits consist of $153.2 million in advances from customers for projects which BPA is constructing on their behalf, $122.6 million paid to BPA from participants under the Third AC intertie capacity agreement, $94.0 million for the Enron settlement, $86.8 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $65.4 million leasing fees for fiber optic cable, $55.5 million for the IOU deferral, $27.0 million current fair market value of certain trading physical forward sales and purchases, written options and Libor interest rate swap transactions, $13.2 million in deferred CSRS, $12.8 million in unearned option premium revenue, and $.1 million in other miscellaneous long-term liabilities.

Advances on projects BPA constructs for customers are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or if BPA retains title, are recorded to revenue over the related useful lives of the assets. Deferred Third AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets.

BPA terminated all remaining contracts with Enron for $99 million effective April 1, 2003. BPA is reimbursing the U.S. Treasury judgment fund for their payment of the settlement through 2006.

Diversification fees are payments by customers to BPA in consideration for a reduction in their contractually obligated power purchases from BPA. Deferred diversification fees and other settlement payments for long-term agreements are recognized as revenue over the original contract terms (diversification fee contracts generally correspond to the rate period ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020.

Payment of a portion of the 2003 IOU subscription settlement benefits were deferred to be paid in 2007 through 2011 unless they are reduced through billing credits offsetting the SN CRAC. The current portion of deferred credits to be recorded as revenue in 2004 is included in accounts payable and other current liabilities in the Balance Sheet.

Hedging and Derivative Instrument Activities

BPA's hedging policy (Policy) allows the use of financial instruments such as commodity futures, options and swaps to hedge the price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development. The Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under specific provisions included in the Policy.

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2003 or 2002.

As of and for the years ended Sept. 30, 2003, 2002 and 2001, both the deferred and the realized gains and losses resulting from these transactions were not material to the consolidated FCRPS financial statements.

Written Options

In prior periods, BPA sold put options for the sale of electricity at certain points in the future. BPA's intention is to take delivery of power as a result of written put options if exercised. The megawatt-hour quantities that BPA sold and the premiums that BPA collected for the sales of these options were priced on market-based information and a mathematical model developed by BPA. This model makes certain assumptions based on historical and other statistical data. Actual future results could vary from estimates resulting in the requirement that BPA may be required to buy power at strike prices above market prices as a result of its written put option obligations.

The following table reflects the written options outstanding.

Written Put Options
As of Sept. 30

	2003	2002
Put Options		
Outstanding	1,972,800 MWh	3,507,600 MWh
Average Strike Price	$40.33	$42.25

These options expire at various times through December 2003. BPA records written options on a mark-to-market basis and includes unrealized gains and losses in operating revenues in the Statement of Revenues and Expenses.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2003 and 2002. The carrying value reflected in the Balance Sheet approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed Libor interest rate swaps to help manage interest rate risk related to its long-term debt portfolio.

In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for the next 10 years and receives a variable rate that changes weekly tied to LIBOR. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for the next 15 years and receives a variable rate that changes weekly tied to LIBOR. The net effect of the two swap transactions is essentially replacing variable rate debt with 3.3 percent fixed rate debt. The swap transaction does not qualify for special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. As of Sept. 30, 2003, BPA recorded a $7.9 million fair value loss in the Statement of Revenues and Expenses related to the interest rate swap transactions.

Adoption of Statement 133 and Related Guidance

BPA adopted SFAS 133, "Accounting for Derivative Instrument and Hedging Activities," as amended, on Oct. 1, 2000. SFAS 133 requires that every derivative instrument be recorded on the Balance Sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," related Derivative Implementation Group (DIG) guidance, and SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." Collectively, these statements are referred to as "SFAS 133." Purchases and sales of forward electricity and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS 133. These transactions are excluded under SFAS 133 and therefore are not required to be fair valued in the financial statements.

For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2003, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

On the date of adoption (Oct. 1, 2000), in accordance with the transition provisions of SFAS 133, BPA recorded a cumulative-effect adjustment of $(168) million in net revenue (expense) to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted mainly of transactions known as bookouts that the FASB initially determined should be fair valued in net revenue (expense).

On June 29, 2001, the FASB issued guidance on Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Issue C15 provided additional guidance on the classification and application of SFAS 133 relating to purchases and sales of electricity utilizing forward contracts and options including bookout transactions. This guidance became effective as of July 1, 2001. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

In April 2003, the FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends financial accounting and reporting for derivative instruments, including the accounting treatment for certain forward power sales and purchase contracts. SFAS 149 is effective for new contracts transacted after July 1, 2003. The normal purchase and sales exception previously allowed for bookout transactions under DIG issue C-15 was effectively eliminated by SFAS 149. However, under SFAS 149, BPA expects to qualify bookout transactions for the normal purchase and normal sale exception unless certain applicable criteria is not met. As of Sept. 30, 2003, the impact of adoption of SFAS 149 is immaterial.

For fiscal years 2003, 2002 and 2001, BPA recorded the following SFAS 133 fair value unrealized gain or loss in the Statement of Revenues and Expenses related to its derivative portfolio.

Fair Value Gains (Losses)
As of Sept. 30 — thousands of dollars

	2003	2002	2001
Physical Power Derivatives	$63,165	$ 38,354	$ 47,877
Interest Rate Swap	(7,900)	—	—
	$55,265	$ 38,354	$ 47,877

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $190 million, $93 million and $6 million at Sept. 30, 2003, 2002 and 2001 respectively. BPA operates as two segments: The Power Business Line and the Transmission Business Line. The table in Note 7 reflects the revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing agency, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS and the payment of certain irrigation costs as discussed in Note 5.

Fish Credits

The NW Power Act obligated the BPA administrator to make expenditures for fish and wildlife protection, mitigation and enhancement for both power and non-power purposes, on a reimbursement basis. It also specified that consumers of electric power, through their rates for power services "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects.

BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism against BPA's Treasury payments to reimburse BPA for expenditures made on behalf of mitigation for non-power purposes. Under the agreed-upon crediting mechanism, BPA reduces its cash payments to Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes. The credits are used to recoup the amount owed to BPA by the other project purposes. BPA has taken this credit since 1995, in amounts that, with the exceptions of fiscal 2001 and 2003, ranged between $26 million and $60 million. Criteria was met permitting draws from the Fish Cost Contingency Fund of the $79 million and $247 million in 2003 and 2001 respectively. The fund is now depleted.

IOU Subscription Settlement Agreements and Residential Exchange

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), beginning in 1982 BPA entered into residential exchange contracts with most of its electric utility customers. These contracts were to result in payments to the utilities if a utility's average system cost exceeded BPA's priority firm power rate.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except Northwestern Energy (formerly the Montana Power Co., which had not been receiving benefits). BPA made payments to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011.

In October 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements, which provide financial benefits in place of residential exchange benefits for the period July 1, 2001, through Sept. 30, 2011. These agreements provide for both sales of power and monetary benefit payments to the IOUs. In fiscal 2003, BPA continued to negotiate a new settlement related to the IOUs benefits. See the Commitments and Contingencies section in Note 5 for additional information. The table below summarizes future IOU benefits as of Sept. 30, 2003, without the new settlement agreement discussed in Note 5.

IOU Exchange Benefits
thousands of dollars

	IOU Benefits
2004	$ 398,655
2005	473,865
2006	457,940
	$1,330,460

Includes approximately $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. Financial benefits beyond the current rate case period cannot currently be quantified.

Recent Accounting Pronouncements

In November 2002, FASB issued FASB Interpretation No. 45 (FIN 45), " Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others – an interpretation of FASB Statements No. 5, 57, and 107, and recission of FASB Interpretation No. 34." FIN 45 clarifies that a guarantor is required to recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. It also elaborates on the disclosures to be made by a guarantor on previously issued guarantees. Because of the guarantee associated with the nonfederal projects, BPA has historically recorded the associated debt, FIN 45 does not have a current effect on the FCRPS financial statements.

In January 2003, FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." FIN 46 clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The Interpretation differentiates between an entity with a majority voting interest (the previous requirement under ARB No. 51) and entities that have controlling financial interest through other arrangements that may not involve any voting interests and how both of these types of entities (variable interest entities) may need to be consolidated. FIN 46 is effective for variable interest entities created after Feb. 1, 2003. BPA is currently evaluating the effect of FIN 46 for arrangements which existed before Feb. 1, 2003. FIN 46 will be effective for BPA for fiscal year ending Sept. 30, 2004.

2. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which BPA is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to Treasury in the absence of the Refinancing Act, plus $100 million. The $100 million was capitalized as part of the appropriations balance and was included pro rata in the new principal of the individual appropriated repayment obligations.

The amount of appropriations refinanced was $6.6 billion. After refinancing, the appropriations outstanding were $4.1 billion. The difference between the appropriated debt before and after the refinancing was recorded as a capitalization adjustment. This adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act.

Amortization of the capitalization adjustment was $67.7 million for fiscal 2003, $67.4 million for 2002, and $68.8 million for 2001. The weighted-average interest rate was 7.0 percent in 2003 and 2002, and 6.9 percent in 2001.

Construction and replacement of Corps and Reclamation generating facilities historically have been financed through annual federal appropriations. Annual appropriations also were made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the National Energy Policy Act of 1992 BPA has begun directly funding operation and maintenance expenses and capital efficiency and reliability improvements for Corps and Reclamation generating facilities.

Federal Generation and Transmission appropriations are repaid to the U.S. Treasury within the weighted average service lives of the associated investments (maximum 50 years) from the time each facility is placed in service.

If, in any given year, revenues are not sufficient to cover all cash needs, including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This interest must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

The table shows the term repayments on the remaining federal appropriations as of Sept. 30, 2003.

Federal Appropriations
thousands of dollars

Term Repayments	
2004	$ 73,484
2005	110,989
2006	68,939
2007	33,694
2008	10,913
2009+	4,382,941
	$4,680,960

Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

3. Long-Term Debt

To finance its capital programs, BPA is authorized by Congress to issue to the U.S. Treasury up to $4.45 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $4.45 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2003, $305 million of conservation bonds and $2,393 million of other borrowings were outstanding. The average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently. As a result, the fair value of the BPA long-term debt, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2003, for similar maturities exceeds carrying value by approximately $304 million, or 11 percent. The table at page 42 reflects the terms and amounts of long-term debt.

4. Nonfederal Projects

BPA has acquired all or part of the generating capability of five nuclear power plants. The contracts to acquire the generating capability of the projects, referred to as "net-billing agreements," require BPA to pay all or part of the annual projects' budgets, including operating expense and debt service, including projects that are not completed and/or not operating. BPA also has acquired all of the output of the Cowlitz Falls and Wasco hydro projects. BPA has agreed to fund debt service on Eugene Water and Electric Board, Emerald, City of Tacoma and Conservation and Renewable Energy System bonds issued to finance conservation programs sponsored by BPA.

BPA recognizes expenses for these projects based upon total project cash funding requirements reflected in project budgets that are adopted by BPA and the projects' owners.

Operating expense of $223 million in fiscal 2003, $175 million in fiscal 2002, and $217 million in fiscal 2001 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $120 million, $230 million, and $473 million for 2003, 2002 and 2001, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses. Refinancing activities reduced debt service by $463 million, $319 million and $158 million for 2003, 2002, and 2001 respectively from rate case estimates.

The fair value of all Energy Northwest debt exceeds recorded value by $443 million or 7.3 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2003. All other nonfederal projects' debt approximates fair value as stated.

U.S. Treasury Bonds

Long-Term Debt (1) — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Construction and Fish & Wildlife	Conservation	Cumulative Total
January 1997	none	2004	6.80%	$ 30,000		$ 30,000
May 1999	none	2004	5.95%	26,200		56,200
June 2001 (2)	none	2004	4.75%	50,000		106,200
July 2000	none	2004	7.00%	50,000		156,200
September 1999 (2)	none	2004	6.40%	20,000		176,200
January 2000	none	2005	7.15%	53,500		229,700
January 2001	none	2005	5.65%	20,000		249,700
January 2001	none	2005	5.65%	25,000		274,700
March 2002	none	2005	4.60%	110,000		384,700
March 2002 (2)	none	2005	4.60%	30,000		414,700
May 1997	none	2005	6.90%	80,000		494,700
June 2002	none	2005	3.75%	60,000		554,700
June 2002	none	2005	3.75%		40,000	594,700
September 2000 (2)	none	2005	6.70%	20,000		614,700
October 2002	none	2005	3.00%	50,000		664,700
November 2002	none	2005	2.80%	40,000		704,700
April 2003 (2)	none	2006	2.40%	40,000		744,700
April 2003 (2)	none	2006	2.40%	25,000		769,700
July 2003	none	2006	2.30%	75,000		844,700
July 2003 (2)	none	2006	2.30%	30,000		874,700
August 1996	none	2006	7.05%	70,000		944,700
September 2000	none	2006	6.75%	40,000		984,700
September 2002	none	2006	3.05%	100,000		1,084,700
September 2002	none	2006	3.05%	30,000		1,114,700
September 2002 (2)	none	2006	3.05%	20,000		1,134,700
September 2003	none	2006	2.50%	20,000		1,154,700
September 2003 (2)	none	2006	2.50%	25,000		1,179,700
December 2002 (2)	none	2006	3.05%	40,000		1,219,700
April 2003	none	2007	2.90%	40,000		1,259,700
July 2003	none	2007	2.95%	25,000		1,284,700
August 1997	none	2007	6.65%	111,300		1,396,000
September 2003	none	2007	3.10%	20,000		1,416,000
April 1998	none	2008	6.00%	75,300		1,491,300
April 1998	none	2008	6.00%	25,000		1,516,300
August 1998	none	2008	5.75%	40,000		1,556,300
September 1998	none	2008	5.30%		104,300	1,660,600
May 1998	none	2009	6.00%	72,700		1,733,300
May 1998	none	2009	6.00%		37,700	1,771,000
July 1989	none	2009	8.55%		40,000	1,811,000
January 2001	none	2010	6.05%	60,000		1,871,000
January 2001	none	2010	6.05%	30,000		1,901,000
January 1996	2001	2011	6.70%		30,000	1,931,000
May 1998	none	2011	6.20%	40,000		1,971,000
June 2001	none	2011	5.95%	25,000		1,996,000
August 2001	none	2011	5.75%	50,000		2,046,000
November 1996	2001	2011	6.95%	40,000		2,086,000
January 1998	none	2013	6.10%	60,000		2,146,000
September 1998	none	2013	5.60%		52,800	2,198,800
February 1999	none	2014	5.90%	60,000		2,258,800
April 1998	2008	2028	6.65%	50,000		2,308,800
August 1998	none	2028	5.85%	106,500		2,415,300
August 1998	none	2028	5.85%	112,300		2,527,600
May 1998	2008	2032	6.70%	98,900		2,626,500
April 2003	2008	2033	5.55%	40,000		2,666,500
October 1993	1998	2033	6.85%	31,254		2,697,754
				$ 2,392,954	$ 304,800	$ 2,697,754
Less current portion						(176,200)
						$ 2,521,554

(1) The weighted average interest rate was 5.3 percent on outstanding long-term debt as of Sept. 30, 2003. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(2) Corps/Reclamation direct funding

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2003.

Nonfederal Projects
thousands of dollars

	Debt Repayments
2004	$ 265,135
2005	234,897
2006	253,632
2007	294,745
2008	307,953
2009+	4,930,231
	$6,286,593

5. Commitments and Contingencies

Net-Billing Agreements

BPA has agreed with Energy Northwest that in the event any participant shall be unable for any reason, or shall 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, unless payment of such unpaid amount is made in a timely manner pursuant to the net-billing agreements.

Purchase and Sales Commitments

BPA has entered into Subscription power sales for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. These contracts run for as short as three and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through 2006. BPA's trading floor enters into sales commitments to sell expected surplus generating capabilities at future dates and purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into these contracts throughout the year to maximize its revenues on estimated surplus volumes. BPA records these sales and purchases in the month the underlying power is sold or purchased.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2003.

Purchase Power and Sales Commitments
thousands of dollars

	Purchase	Sales
2004	$ 662,918	$ 1,795,554
2005	704,548	1,602,745
2006	650,867	1,689,882
2007	48,882	87,393
2008	49,525	71,114
2009+	152,475	264,726
	$2,269,215	$5,511,414

Augmentation commitments run through 2006.

Decommissioning and Restoration Costs

In 1999 Energy Northwest successfully transferred assets and site restoration liability for WNP-3 to a consortium of local governments named the Satsop Redevelopment Project. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation Council (EFSEC) that complied with EFSEC's requirement to restore the WNP-1 and WNP-4 sites with minimal hazard to the public. This plan updated Energy Northwest's June 1995 plan. EFSEC's approval recognized that uncertainty still exists as to the exact details of the proposed plan; accordingly, EFSEC's conditional approval provided for additional reviews once the details of the plan are finalized. As part of submitting the restoration plan to EFSEC, Energy Northwest obtained outside estimates for site restoration of WNP-1 and WNP-4. BPA is required to fund site restoration for WNP-1. Funding for WNP-4 is uncertain. The cost of complete site restoration for WNP-1 and WNP-4 is estimated to be up to

$60 million and $40 million respectively. BPA and Energy Northwest have been negotiating a reduced level of site restoration for WNP-1 as well as WNP-4 with EFSEC and the Department of Energy. A tentative conceptual solution involving a reduced level and delay in accomplishing restoration has been reached. EFSEC has approved a revised plan prepared by Energy Northwest (December 2002 Site Restoration Plan) and the agreement should be executed by the end of December 2003. The estimated cost for the recommended level of site restoration at WNP-1 and WNP-4 is about $25 million and $23 million (2003 dollars) respectively. BPA believes the existing funds plus earnings will be adequate to cover most if not all site restoration costs. BPA has recorded an estimated liability of $25.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for WNP-1 decommissioning costs.

Decommissioning costs for Columbia Generating Station are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for Columbia Generating Station. The sinking fund is expected to provide for decommissioning at the end of the project's operating life in accordance with Nuclear Regulatory Commission requirements. Sinking fund requirements for Columbia Generating Station are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning and site restoration expenditures for Columbia Generating Station is $673 million (2003 dollars). BPA has recorded an estimated liability of $47.8 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking fund for the years ended Sept. 30, 2003, 2002 and 2001 were approximately $4.6 million per year. The sinking fund balance at Sept. 30, 2003, is $84 million.

In January 1993, the Portland General Electric board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $265 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2003, BPA's 30-percent share of this estimated remaining liability is $52.3 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143). The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements will be greater in the early years of decommissioning and then will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for 2001, 2002 and 2003. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In 2002 and 2003, the decommissioning trust fund was used to fund a portion of the 2002 and 2003 Trojan decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover its share of Trojan's costs through rates and decommissioning trust fund withdrawals. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses. These costs incorporate the impacts of SFAS 143 as implemented by PGE.

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 types of insurance coverage purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decommissioning Liability and Excess Property Insurance; and 3) Business Interruption and/or Extra Expense Insurance.

Under each insurance policy BPA could be subject to an 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 Insurance policy is $6.6 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $13 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.5 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 $300 million, BPA could be subject to a retrospective assessment of $95.8 million limited to an annual maximum of $10 million.

Endangered Species Act

Actions related to the Endangered Species Act are included in BPA's costs and recovered through current rates.

Environmental Cleanup

From time to time, there are sites where BPA, Corps or Reclamation have been or may be identified as a potential responsible party. Costs associated with cleanup of those sites are not expected to be material to the FCRPS financial statements and would be recoverable through future rates.

Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2008.

Irrigation Assistance

As directed by legislation, BPA is required to make cash distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects that have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation and are required only if doing so does not result in an increase to power rates. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues (expenses) when paid. BPA paid irrigation assistance payments of $25 million and $17 million for 1997 and 2001 respectively. Future irrigation assistance payments ultimately could total $673 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin Project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users 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.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2003.

Irrigation Assistance
thousands of dollars

	Distributions
2004	$ 739
2005	—
2006	—
2007	—
2008	2,950
2009+	669,787
	$673,476

On Dec. 11, 2002, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2001) from the Bureau of Reclamation. The numbers above, reflect that new schedule. They exclude $56.6 million assistance for Lower Teton which was never completed therefore never produced electricity and the administrator has no obligation to recover these costs.

IOU Monetary Benefits

During fiscal 2003, BPA and various customer representatives negotiated a proposed litigation settlement that would, among other things, affect IOU Monetary Benefits if the settlement becomes effective. (The proposed settlement would also dismiss a number of existing lawsuits, preclude certain future lawsuits, result in lower 2004 rates through a reduction in the SN CRAC, and bind parties to a number of other commitments that do not have a current financial statement impact.) Subsequent to year-end, on Oct. 21, 2003, BPA signed and offered the proposed settlement to regional customers that are party to the litigation that the proposed settlement would dismiss. Three parties signed the proposed settlement by Oct. 23, 2003, making the settlement effective, but subject to the condition of subsequent actions by a number of parties over the following 120 day period for the settlement to remain in effect. During this 120-day period, in order for the proposed settlement to remain in effect, a number of other parties must sign the appropriate settlement agreements.

Under the proposed settlement, the method for establishing the IOUs' Monetary Benefits for the fiscal 2007 through 2011 period would be established, and BPA's option to provide power to the IOUs during that period would be relinquished. A portion of IOU Monetary Benefits currently scheduled to be paid out in fiscal 2004 through 2006 would be deferred to 2007 through 2011, and most of the deferral amounts could no longer be reduced through billing credits offsetting the IOUs' SN CRAC charges. The settlement would also eliminate the $200 million risk contingency payment owed to two IOUs that have load reduction contracts. However, if the settlement is terminated as the result of certain events during the 120-day period, BPA would expect to have to pay the $200 million in accordance with the terms of the contracts. The $200 million is considered augmentation costs and, if paid, would then be collected through the LB CRAC.

6. Litigation

The FCRPS is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the FCRPS is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the FCRPS's financial position or results of operations.

7. Segments

In 1997 BPA opted to implement FERC's open-access rulemaking and standards of conduct. FERC requires that transmission activities are functionally separate from wholesale power merchant functions and that transmission is provided in a nondiscriminatory open-access manner.

The FCRPS's major operating segments are defined by the utility functions of generation and transmission. The Power Business Line represents the operations of the generation function, while the Transmission Business Line represents the operations of the transmission function. The business lines are not separate legal entities. Where applicable, "Corporate" represents items that are necessary to reconcile to the financial statements, which generally include shared activity and eliminations. Each FCRPS segment operates predominantly in one industry and geographic region: the generation and transmission of electric power in the Pacific Northwest.

The FCRPS centrally manages all interest expense activity. Since the Bonneville Power Administration has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed in the SFAS 131 Segment Reporting table. Unaffiliated revenues represent sales to external customers for each segment. Inter-segment revenues are eliminated.

FCRPS management evaluates the performance of the business lines based on Net Operating Margin (NOM) and does not track the separate balance sheets or net revenues on a business line level. NOM represents revenues generated from operations less operating and maintenance expenses of the segment's revenue-generating assets. On a consolidated basis, this amount represents $1,249 million for 2003 ($3,612 million Operating Revenues less $55 million SFAS 133 mark-to-market, $175 million U.S. Treasury Credits for Fish, $1,199 million Operations and Maintenance and $1,043 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

Major Customers

During 2003, 2002 and 2001, no single customer represented 10 percent or more of the FCRPS's revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Corporate	Total
2003				
Unaffiliated Revenues	$ 3,059,386	$ 552,718	$ —	$ 3,612,104
Intersegment Revenues	85,425	110,884	(196,309)	—
Operating Revenues	$ 3,144,811	$ 663,602	$ (196,309)	$ 3,612,104
Net Operating Margin	$ 1,184,846	$ 337,353	$ (272,818)	$ 1,249,381
2002				
Unaffiliated Revenues	$ 2,967,075	$ 566,654	$ —	$ 3,533,729
Intersegment Revenues	80,729	153,727	(234,456)	—
Operating Revenues	$ 3,047,804	$ 720,381	$ (234,456)	$ 3,533,729
Net Operating Margin	$ 927,061	$ 355,870	$ (288,547)	$ 994,384
2001				
Unaffiliated Revenues	$ 3,824,658	$ 454,011	$ —	$ 4,278,669
Intersegment Revenues	63,394	192,662	(256,056)	—
Operating Revenues	$ 3,888,052	$ 646,673	$ (256,056)	$ 4,278,669
Net Operating Margin	$ 180,790	$ 363,822	$ (161,587)	$ 383,025

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2003 — thousands of dollars

Schedule A

		Commercial Power			Irrigation *(unaudited)*		
	Total Plant	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation
Bonneville Power Administration							
Transmission Facilities	$ 5,787,429	$ 5,360,934	$ 426,495	$ 5,787,429	$ —	$ —	$ —
Bureau of Reclamation							
Boise	138,215	17,169	3,920	21,089	(363)	68,219	67,856
Columbia Basin	1,930,254	1,234,556	33,140	1,267,696	494,514	143,955	638,469
Green Springs	35,579	11,178	62	11,240	9,934	8,070	18,004
Hungry Horse	148,957	121,808	223	122,031	—	—	—
Minidoka-Palisades	382,454	109,789	787	110,576	386	72,966	73,352
Yakima	258,946	6,139	60	6,199	13,821	127,511	141,332
Total Bureau Projects	2,894,405	1,500,639	38,192	1,538,831	518,292	420,721	939,013
Corps of Engineers							
Albeni Falls	48,868	42,665	1,535	44,200	—	—	—
Bonneville	1,382,775	878,749	99,719	978,468	—	—	—
Chief Joseph	625,023	568,853	15,700	584,553	—	163	163
Cougar	104,922	20,332	42,396	62,728	—	3,288	3,288
Detroit-Big Cliff	70,272	41,220	2,926	44,146	—	5,050	5,050
Dworshak	375,281	316,522	2,095	318,617	—	—	—
Green Peter-Foster	95,966	49,787	5,851	55,638	—	6,222	6,222
Hills Creek	51,077	18,394	998	19,392	—	4,616	4,616
Ice Harbor	217,312	151,874	5,764	157,638	—	—	—
John Day	649,960	485,992	16,579	502,571	—	—	—
Libby	576,024	430,559	2,797	433,356	—	—	—
Little Goose	253,747	209,179	2,921	212,100	—	—	—
Lookout Point-Dexter	109,199	49,738	7,184	56,922	—	1,498	1,498
Lost Creek	149,983	26,988	35	27,023	—	2,190	2,190
Lower Granite	408,326	329,683	5,002	334,685	—	—	—
Lower Monumental	271,464	226,219	2,572	228,791	—	—	—
McNary	376,127	288,752	13,463	302,215	—	—	—
The Dalles	412,311	304,378	58,489	362,867	—	—	—
Lower Snake	261,019	255,964	2,502	258,466	—	—	—
Columbia River Fish Bypass	885,643	316,377	527,698	844,075	—	—	—
Total Corps Projects	7,325,299	5,012,225	816,226	5,828,451	—	23,027	23,027
AFUDC on Direct Funded Projects	27,711	—	27,711	27,711	—	—	—
Irrigation Assistance at 12 Projects having no power generation	196,150	—	—	—	153,381	42,769	196,150
Total Plant Investment	16,230,994	11,873,798	1,308,624	13,182,422	671,673	486,517	1,158,190
Repayment Obligation Retained by Columbia Basin Project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton Project	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$ 16,314,740	**$ 11,876,634**	**$ 1,315,893**	**$ 13,192,527**	**$ 730,049**	**$ 490,198**	**$ 1,220,247**

(1) Amount represents joint costs transferred to Bureau of Sports Fisheries and Wildlife. This is included in other assets in the accompanying balance sheets.

(2) The $7,269,000 commercial power portion of the Teton project is included in other assets in the accompanying balance sheets. Teton amounts exclude interest totaling approximately $2.2 million subsequent to June 1976, which was charged to expense.

	Non-reimbursable *(unaudited)*					
	Navigation	Flood Control	Fish and Wildlife	Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	49,270	15.00%
Columbia Basin	—	17,116	6,073	175	725	91.29%
Green Springs	—	—	—	—	6,335	59.51%
Hungry Horse	—	26,926	—	—	—	81.92%
Minidoka-Palisades	—	64,397	2,568	10,494	121,067	29.01%
Yakima	—	2,479	51,044	289	57,603	7.73%
Total Bureau Projects	—	110,918	59,685	10,958	235,000	71.07%
Corps of Engineers						
Albeni Falls	180	271	—	4,217	—	90.45%
Bonneville	400,979	—	—	1,266	2,062	70.76%
Chief Joseph	—	—	4,977	6,330	29,000	93.53%
Cougar	548	38,358	—	—	—	59.79%
Detroit-Big Cliff	219	20,857	—	—	—	62.82%
Dworshak	9,636	31,561	—	15,467	—	84.90%
Green Peter-Foster	366	30,377	—	1,693	1,670	57.98%
Hills Creek	630	26,439	—	—	—	37.97%
Ice Harbor	56,159	—	—	3,515	—	72.54%
John Day	90,980	18,038	—	11,962	26,409	77.32%
Libby	—	95,190	876	15,965	30,637	75.23%
Little Goose	34,913	—	—	4,130	2,604	83.59%
Lookout Point-Dexter	749	49,428	—	602	—	52.13%
Lost Creek	—	53,105	24,541	29,481	13,643	18.02%
Lower Granite	52,600	—	—	13,199	7,842	81.97%
Lower Monumental	39,382	—	—	2,874	417	84.28%
McNary	69,004	—	—	4,908	—	80.35%
The Dalles	47,344	—	—	2,078	22	88.01%
Lower Snake	2,553	—	—	—	—	99.02%
Columbia River Fish Bypass	38,798	2,770	—	—	—	95.31%
Total Corps Projects	845,040	366,394	30,394	117,687	114,306	79.57%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.20%
Total Plant Investment	845,040	477,312	90,079	128,645	349,306	85.36%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project	—	9,151	—	2,433	—	80.70%
	$ 845,040	**$ 486,463**	**$ 90,079**	**$ 131,078**	**$ 349,306**	**85.34%**

APPENDIX B-2

FEDERAL SYSTEM UNAUDITED FINANCIAL STATEMENTS FOR THE THREE MONTHS ENDED DECEMBER 31, 2003

(THIS PAGE INTENTIONALLY LEFT BLANK)

QUARTERLY REPORT FOR THE THREE MONTHS ENDED DECEMBER 31, 2003
Federal Columbia River Power System

Comparative Balance Sheets (Unaudited)
(Thousands of Dollars)

	December 31	
	2003	2002
Assets		
Utility Plant		
Completed plant	**$11,920,309**	$11,549,642
Accumulated depreciation	**(4,343,015)**	(4,115,225)
	7,577,294	7,434,417
Construction work in progress	**1,359,880**	1,225,365
Net utility plant	**8,937,174**	8,659,782
Nonfederal Projects	**6,285,218**	6,200,082
Decommissioning Cost	**123,788**	73,861
Conservation, net of accumulated amortization	**369,724**	402,236
Fish & Wildlife, net of accumulated amortization	**122,526**	130,326
Current Assets	**1,359,219**	1,098,195
Other Assets	**230,636**	157,320
	$17,428,285	$16,721,802
Capitalization and Liabilities		
Accumulated Net Revenues (Expenses)	**$513,533**	($51,762)
Federal Appropriations	**4,615,558**	4,603,510
Capitalization Adjustment	**2,107,800**	2,175,474
Long-Term Debt	**2,521,554**	2,653,141
Nonfederal Projects Debt	**6,044,877**	5,956,806
Decommissioning Reserve	**123,789**	63,861
Current Liabilities	**891,993**	857,737
Deferred Credits	**609,182**	463,035
	$17,428,286	$16,721,802

Comparative Statements of Revenues and Expenses (Unaudited)
(Thousands of Dollars)

	Three months ended December 31		Twelve months ended December 31	
	2003	2002	**2003**	2002
Operating Revenues:				
Revenues	**$789,633**	$873,723	**$3,244,187**	$3,392,442
SFAS 133 mark-to-market (loss) gain	**(1,210)**	47,134	**6,921**	133,554
Other revenues	**13,994**	10,029	**57,643**	52,893
U.S. Treasury credits for fish	**19,654**	14,996	**179,542**	32,459
Total Operating Revenues	**822,071**	945,882	**3,488,293**	3,611,348
Operating Expenses:				
Operations and maintenance	**226,477**	263,687	**1,161,311**	1,320,077
Purchased power	**198,099**	294,294	**946,814**	1,154,831
Non-Federal projects	**64,322**	55,204	**128,652**	198,365
Federal projects depreciation	**88,836**	85,094	**353,767**	340,036
Total Operating Expenses	**577,734**	698,279	**2,590,544**	3,013,309
Net operating revenues (expenses)	**244,337**	247,603	**897,749**	598,039
Interest Expense	**74,576**	87,713	**332,454**	352,975
Net Revenues	**$169,761**	$159,890	**$565,295**	$245,064

Derivative Instruments and Hedging Activities

The SFAS 133 mark-to-market (MTM) amount is an "accounting only" (no cash impact) adjustment representing the MTM adjustment required by SFAS 133, as amended, for identified derivative instruments.

(THIS PAGE INTENTIONALLY LEFT BLANK)

APPENDIX C

FORM OF OPINION OF ORRICK, HERRINGTON & SUTCLIFFE LLP

[Closing Date]

Northwest Infrastructure Financing Corporation
c/o J.H. Management Corporation
One International Place, Room 4350
Boston, MA 02110-2916

Re: Northwest Infrastructure Financing Corporation
Transmission Facilities Lease Revenue Bonds
Series 2004

Ladies and Gentlemen:

We have acted as special counsel to the United States of America, Department of Energy, acting by and through the Administrator of the Bonneville Power Administration ("Bonneville") in connection with the issuance by the Northwest Infrastructure Financing Corporation (the "Issuer") of $119,585,000 aggregate principal amount of the Issuer's Transmission Facilities Lease Revenue Bonds, Series 2004 (the "Series 2004 Bonds"), issued pursuant to an Indenture of Trust, dated as of March 1, 2004 (the "Indenture"), between the Issuer and U.S. Bank National Association, as trustee (the "Trustee"). The Series 2004 Bonds are issued for the purpose of financing a portion of the cost of acquiring, constructing, improving and equipping certain transmission facilities to be owned by the Issuer and leased to Bonneville pursuant to the Lease Agreement, dated as of March 1, 2004 (the "Lease Agreement"), between the Issuer and Bonneville. Capitalized terms not otherwise defined herein shall have the meanings ascribed to such terms in the Indenture.

In such connection, we have reviewed the Indenture, the Lease Agreement, opinions of counsel to Bonneville, the Trustee and the Issuer, certain resolutions of the Issuer, certificates of the Issuer, the Trustee, Bonneville and others and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein. With respect to the due organization and existence of the Issuer and the valid authorization, execution and delivery of the Indenture, the Lease Agreement and the Series 2004 Bonds by the Issuer, we have relied upon the opinion of Ropes & Gray LLP.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Our engagement with respect to the Series 2004 Bonds has concluded with their issuance, and we disclaim any obligation to update this letter.

We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Issuer.

We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in such documents, and of the legal conclusions contained in the opinions referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture and the Lease Agreement.

We call attention to the fact that the rights and obligations under the Series 2004 Bonds, the Indenture and the Lease Agreement and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other similar laws relating to or affecting creditors' rights, to the application of equitable principles and to the exercise of judicial discretion in appropriate cases. In addition, under Washington law, any provision of the Lease Agreement requiring one party to pay the other party's attorneys' fees and costs in actions to enforce the provisions thereof will be construed to entitle the prevailing party in any action to be awarded reasonable attorneys' fees, costs and necessary disbursements. Also, notwithstanding any provisions in the Lease Agreement to the effect that the Lease Agreement reflects the entire understanding of the parties thereto with respect to the matters described therein, the courts of the State of Washington may consider extrinsic evidence of the circumstances surrounding the negotiation and execution of the Lease Agreement to ascertain the intent of the parties in using the language employed in the Lease Agreement, regardless of whether or not the meaning of the language used in the Lease Agreement is plain and unambiguous on its face, and may determine that additional or supplemental terms can be incorporated into the Lease Agreement. Furthermore, under Washington law, the parties to the Lease Agreement can modify the Lease Agreement by their conduct, and a party seeking to enforce the Lease Agreement may be required to perform its obligations under the Lease Agreement.

We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum or waiver provisions contained in the foregoing documents nor do we express any opinion with regard to the state or quality of title to or interest in any of the real or personal property described in the Indenture or the Lease Agreement or the accuracy or sufficiency of the description of any such property contained therein. Finally, we have undertaken no responsibility for the accuracy, completeness or fairness of the Offering Memorandum or other offering material relating to the Series 2004 Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Series 2004 Bonds constitute the valid and binding limited recourse obligations of the Issuer, payable solely from the Trust Estate.

2. The Indenture constitutes the valid and binding obligation of the Issuer. The Indenture creates the valid pledge of the Trust Estate, subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture.

3. The Lease Agreement constitutes the valid and binding agreement of the Issuer.

Very truly yours,

ORRICK, HERRINGTON, SUTCLIFFE LLP

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

Recycled Paper - Printed by
IMAGEMASTER 800.452.5152