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NEW ISSUE—Full Book-Entry Ratings: See "RATINGS" herein.

In the opinion of Bond Counsel, interest on the 2003 Bonds will be excluded from gross income subject to federal income taxation pursuant to the Internal Revenue Code of 1986, as amended, subject to certain conditions and assumptions described herein under "TAX EXEMPTION." The 2003 Bonds are not private activity bonds. Interest on the 2003 Bonds is included in the computation of certain federal taxes on corporations.

TACOMA POWER
TACOMA PUBLIC UTILITIES

CITY OF TACOMA, WASHINGTON
Conservation System Project
Revenue Refunding Bonds, 2003
$17,065,000

Dated: Date of Delivery **Due: December 1, as shown below**

The City of Tacoma, Washington Conservation System Project Revenue Refunding Bonds, 2003 (the "2003 Bonds") will be issued as fully registered bonds under a book-entry-only system, initially registered in the name of Cede & Co. (the "Registered Owner"), as nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2003 Bonds. Individual purchases of the 2003 Bonds will be made in the principal amount of $5,000 or any integral multiple thereof within a single maturity. Purchasers of the 2003 Bonds (the "Beneficial Owners") will not receive certificates representing their interest in the 2003 Bonds. Principal and interest are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Bond Registrar").

Principal is payable as set forth on this cover. Interest on the 2003 Bonds is payable on December 1, 2003, and semiannually thereafter on each June 1 and December 1 to maturity or earlier redemption, by the Bond Registrar to DTC, which in turn is obligated to remit principal and interest to its broker-dealer participants for subsequent disbursement to Beneficial Owners of the 2003 Bonds. See APPENDIX D —"BOOK-ENTRY SYSTEM."

The 2003 Bonds are not subject to redemption prior to their stated maturities.

MATURITIES, AMOUNTS, INTEREST RATES AND YIELDS

Year (December 1)	Amount	Interest Rate	Yield	CUSIP No.	Year (December 1)	Amount	Interest Rate	Yield	CUSIP No.
2003	$ 1,120,000	2.00%	1.08%	873470AW8	2010	$ 1,505,000	4.00%	3.24%	873470BD9
2004	1,150,000	5.00	1.38	873470AX6	2011	1,555,000	3.30	3.47	873470BE7
2005	1,215,000	5.00	1.59	873470AY4	2012	100,000	3.90	3.59	873470BF4
2006	1,265,000	3.00	1.86	873470AZ1	2012	1,525,000	5.00	3.59	873470BK3
2007	1,310,000	5.00	2.29	873470BA5	2013	1,705,000	5.00	3.71	873470BG2
2008	1,380,000	5.00	2.63	873470BB3	2014	1,000,000	5.00	3.83	873470BH0
2009	100,000	3.75	2.92	873470BC1	2014	790,000	4.00	3.83	873470BL1
2009	1,345,000	4.00	2.92	873470BJ6					

The 2003 Bonds are being issued to provide funds necessary to refund the Conservation System Project Revenue Bonds, 1994, issued in the principal amount of $22,185,000 (the "1994 Bonds") for the purpose of financing the Conservation Project by the City, and to pay costs of issuance of the 2003 Bonds. See "PURPOSE OF THE 2003 BONDS AND APPLICATION OF THE 2003 BOND PROCEEDS."

The United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

("Bonneville") has entered into a Conservation Project Agreement with the City under which Bonneville is acquiring the energy savings from the Conservation Project (the "Project Agreement"). See APPENDIX E —"SUMMARY OF THE PROJECT AGREEMENT." Pursuant to the Project Agreement, Bonneville is obligated to pay debt service on the 2003 Bonds whether or not the Conservation Project is terminated, operating or operable. Bonneville's payments under the Project Agreement may be made solely from the Bonneville Fund. Such obligations 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 2003 Bonds are special limited obligations of the City payable from the revenues derived from the Conservation Project, a separate system of the Light Division, doing business as Tacoma Power, and are not obligations of the State of Washington or of any political subdivision thereof, other than the City. The 2003 Bonds do not constitute a general obligation of the City or a charge upon the Electric System or any general fund or upon any money or property of the City except the Conservation Revenues, as described herein, and money in certain funds and accounts held under the Second Supplemental Ordinance.

This cover page is not intended to be a summary of the terms of, or security for, the 2003 Bonds. Investors are advised to read the entire Official Statement to obtain information essential to making an informed investment decision.

The 2003 Bonds are offered for delivery when, as and if issued and received by the Underwriters, subject to prior sale, to withdrawal or modification of the offer without notice, and to the approval of legality by Preston Gates & Ellis LLP, Bond Counsel, Seattle, Washington. Certain legal matters will be passed upon for the Underwriters by their counsel, Foster Pepper & Shefelman, PLLC, Seattle, Washington. It is expected that the 2003 Bonds will be delivered on or about June 2, 2003 at the facilities of DTC in New York, New York, or to the Bond Registrar on behalf of DTC by Fast Automated Securities Transfer.

Seattle-Northwest Securities Corporation **Goldman, Sachs & Co.**

Dated: May 13, 2003

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TACOMA PUBLIC UTILITIES
3628 South 35th Street
Tacoma, Washington 98409
(253) 502-8512

MAYOR AND TACOMA CITY COUNCIL

Bill Baarsma, Mayor

Bil Moss, Deputy Mayor	Sharon McGavick
Mike Lonergan	Doug Miller
Kevin Phelps	Connie Ladenburg
William Evans	Rick Talbert

PUBLIC UTILITY BOARD

Robert Lane, Chair

Tom Hilyard, Vice Chair	Doug Erwin
William Barker, Secretary	Jake Fey

DEPARTMENT OF PUBLIC UTILITIES, TACOMA POWER

Mark Crisson, Director of Utilities
Steven J. Klein, Superintendent
Gary Armfield, Transmission and Distribution Manager
Steve Hatcher, Energy Services Manager
Patrick McCarty, Generation Manager
George Whitener, Power Manager
Dana Toulson, Telecommunications Manager

Steve Marcotte, Director of Finance
Mark Bubenik, Chief Assistant City Attorney

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Steven G. Hickok, Deputy Administrator
Ruth B. Bennett, Acting Chief Operating Officer
Randy A. Roach, Vice President, General Counsel
James H. Curtis, Chief Financial Officer

FINANCIAL ADVISOR TO BONNEVILLE POWER ADMINISTRATION

Public Financial Management, Inc.
New York, New York

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IN CONNECTION WITH THE OFFERING OF THE 2003 BONDS, THE UNDERWRITERS MAY OVER ALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2003 BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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CITY OF TACOMA, WASHINGTON

OFFICIAL STATEMENT

$17,065,000
CONSERVATION SYSTEM PROJECT REVENUE REFUNDING BONDS, 2003

INTRODUCTORY STATEMENT

The purpose of this Official Statement, including its appendices, is to provide information concerning the City of Tacoma, Washington's (the "City") Conservation System Project Revenue Refunding Bonds, 2003 (the "2003 Bonds"). The 2003 Bonds will be issued pursuant to (1) Substitute Ordinance No. 25623 approved November 8, 1994 and Substitute Resolution No. 32847 approved on December 13, 1994 (collectively, the "Bond Ordinance") authorizing the Conservation System Revenue Bonds of the City to be issued in series, making covenants in connection with the issuance of such bonds and authorizing the sale of the first series of bonds dated December 1, 1994 in the aggregate principal amount of $22,185,000 (the "1994 Bonds"); (2) Second Supplemental Ordinance No. 27074 approved April 1, 2003 and Substitute Resolution No. 35850 approved May 13, 2003 (collectively, the "Second Supplemental Ordinance") authorizing the issuance of the 2003 Bonds for purposes of refunding the 1994 Bonds; and (3) chapters 35.92, 39.46, and 39.53 RCW. See APPENDIX B—"SUMMARY OF THE BOND ORDINANCE." Unless otherwise specifically defined, certain capitalized terms used in this Official Statement have the meanings given to such terms in the Bond Ordinance and the Second Supplemental Ordinance. See APPENDIX B—"SUMMARY OF THE BOND ORDINANCE — Certain Definitions Used in the Bond Ordinance."

The proceeds of the 2003 Bonds will be used to provide funds necessary to refund the 1994 Bonds and to pay the costs of issuance of the 2003 Bonds. See "PURPOSE OF THE 2003 BONDS AND APPLICATION OF 2003 BOND PROCEEDS."

Bonneville Power Administration ("Bonneville") entered into a Conservation Project Agreement, dated February 23, 1994, with the City (the "Project Agreement") pursuant to which Bonneville agreed to acquire the conservation energy savings generated by the Conservation Project and Bonneville is obligated to pay all Annual Project Costs and Debt Service on all 2003 Bonds. See APPENDIX E —"SUMMARY OF THE PROJECT AGREEMENT."

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 30 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which are constructed and operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally owned projects. Bonneville sells and exchanges power under contracts with over 100 utilities in the Pacific Northwest and Pacific Southwest and with several industrial customers. It also owns and operates a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest. See "THE BONNEVILLE POWER ADMINISTRATION."

Bonneville's primary customer service area is the Pacific Northwest region, an area comprised of Oregon, Washington, Idaho, western Montana and small portions of California, Nevada, Utah and Wyoming (sometimes referred to herein as the "Pacific Northwest," the "Northwest," the "Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville also exports power that is surplus to the needs of the Region to the Pacific Southwest, primarily to California.

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

The City is a municipal corporation under the constitution and laws of the State of Washington. The Light Division, doing business as Tacoma Power ("Tacoma Power"), of the City's Department of Public Utilities (the "Department") operates the City's electrical generation and distribution facilities and telecommunication infrastructure (the "Electric System"). Tacoma Power is one of the largest publicly-owned utilities in the Pacific Northwest in terms of customers served and energy sold. In 2002, Tacoma Power served an average of 154,000 retail customers, had approximately 760 employees and had operating revenues of approximately $288 million. See "THE DEPARTMENT OF PUBLIC UTILITIES—TACOMA POWER."

The proceeds of the 1994 Bonds were used by Tacoma Power to fund conservation measures undertaken by its customers. These measures included payments made to customers to assist with the costs of insulating homes and apartment buildings, incentive payments to apartment owners for reducing the energy necessary to light common areas, payments to residential customers for replacing incandescent light bulbs with fluorescent light bulbs, incentive payments to residential customers for replacing old electric water heaters, providing energy efficient showerheads to certain customers, and providing commercial and industrial customers with financial assistance for installing energy efficient lighting, refrigeration, heating, ventilation and air conditioning improvements. Tacoma Power fully expended the proceeds of the 1994 Bonds. Tacoma Power has discontinued some of the conservation measures that the 1994 Bonds financed.

This Official Statement includes summaries of the terms of the 2003 Bonds, the Bond Ordinance, the Second Supplemental Ordinance and the Project Agreement. The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, report or instrument.

This introduction is qualified in its entirety by reference to the entire Official Statement and a full review of the Official Statement should be made by potential investors. This Official Statement speaks only as of its date and the information contained in it is subject to change.

PURPOSE OF THE 2003 BONDS AND APPLICATION OF 2003 BOND PROCEEDS

PURPOSE OF THE 2003 BONDS

Proceeds of the 2003 Bonds will be used to refund the 1994 Bonds in order to effect a debt service savings and to pay the costs of issuance of the 2003 Bonds. To accomplish this refunding, proceeds of the 2003 Bonds will be used to provide the payment of principal and interest on all of the outstanding $16,330,000 of the 1994 Bonds maturing in the years 2004 through 2015 (the "Refunded Bonds"). The Refunded Bonds shall be called for redemption at a price of 100% on January 1, 2005.

Proceeds of sale of the 2003 Bonds shall be credited to the Refunding Account, which is to be drawn upon for the sole purpose of paying the principal of and interest on the Refunded Bonds until their respective dates of redemption and of paying costs related to the refunding of the Refunded Bonds. Money in the Refunding Account shall be used immediately upon receipt to defease the Refunded Bonds and to pay costs of issuance of the 2003 Bonds.

The City shall defease the Refunded Bonds and discharge such obligations by the use of money in the Refunding Account to purchase certain Government Obligations (referred to as "Acquired Obligations"), bearing such interest and maturing as to principal and interest in such amounts and at such times which, together with any necessary beginning cash balance, will provide payment of: (1) interest and principal on the Refunded Bonds due and payable through and including January 1, 2005 and (2) the redemption price of 100% of the principal amount of the Refunded Bonds on January 1, 2005.

VERIFICATION OF MATHEMATICAL CALCULATIONS

The accuracy of (1) the mathematical computations as to the adequacy of the principal of and interest on the Acquired Obligations to be purchased and held by U.S. Bank National Association (the "Escrow Agent") to pay the redemption price of and interest on the Refunded Bonds as described above, and (2) the mathematical computations supporting the conclusion of Bond Counsel that the Bonds are not "arbitrage bonds" under Section 148 of the Internal Revenue Code of 1986, as amended, will be verified by Grant Thornton LLP, a firm of independent certified public accountants.

SECURITY FOR THE 2003 BONDS

PLEDGE OF CONSERVATION REVENUES

The 2003 Bonds are special limited obligations of the City payable from and secured solely by (i) Conservation Revenues, which include all income, revenue and payments derived by the City in connection with the Conservation Project, including payments received or receivable pursuant to the Project Agreement, except any reward payments as described in the Project Agreement, Trustee Costs, and any loan repayments returned to the City if permitted by the Project Agreement (see APPENDIX B —"SUMMARY OF THE BOND ORDINANCE — Certain Definitions Used in the Bond Ordinance" for the complete definition of Conservation Revenues), (ii) the proceeds of the sale of the 2003 Bonds and any bonds hereafter issued on a parity with the 2003 Bonds ("Future Parity Bonds") to the extent held in funds established under the Bond Ordinance and (iii) money and assets, if any, credited to the Conservation Project Revenue Fund, the Bond Fund, or any junior lien fund except proceeds from junior lien obligations, exclusive of money to be rebated to the federal government. Conservation Revenues do not include any revenue derived by the City from the Electric System or any future separate system of the Light Division or other system or fund of the City. The Bonds do not constitute an obligation of the State of Washington (the "State") or of any political subdivision thereof, other than the City. See "SECURITY FOR THE 2003 BONDS — Conservation Project Agreement" and APPENDIX E —"SUMMARY OF THE PROJECT AGREEMENT."

All outstanding 2003 Bonds and Future Parity Bonds (collectively referred to as the "Bonds") shall be equally and ratably payable and secured under the Bond Ordinance without priority, except as to proceeds of credit enhancements which may be obtained by the City to assure the repayment of one or more series or maturities within a series.

CONSERVATION PROJECT AGREEMENT

Bonneville entered into the Project Agreement with the City to acquire conservation energy savings. The Conservation Project Agreement became effective on February 23, 1994. In the Project Agreement, the City agrees to deliver and Bonneville agrees to purchase the entire Conservation Project's average megawatt Energy Savings Achieved (defined in APPENDIX E) during the term of the Project Agreement. In accordance with the Project Agreement, Bonneville has agreed to pay the Trustee amounts sufficient to pay principal of, premium, if any, and interest due on the Bonds, whether or not the Conservation Project has been completed, terminated, is operating or operable, or its installation, use or the Energy Savings Achieved have been suspended, interrupted, interfered with, reduced, curtailed or terminated in whole or in part, and notwithstanding the performance or nonperformance of either party to the Project Agreement or any other agreement. See APPENDIX E —"SUMMARY OF THE PROJECT AGREEMENT."

SOURCE OF BONNEVILLE'S PAYMENTS: THE BONNEVILLE FUND

Payments by Bonneville under the Project 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 Project 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 "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 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 2002 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, including payments with respect to the 2003 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may only make payments to the United States Treasury from net proceeds; all cash payments of Bonneville, including payments with respect to the 2003 Bonds 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, 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 ("EWEB")) 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 "BONNEVILLE POWER ADMINISTRATION — Power Business Line — Description of the Generation Resources of the Federal System Energy Northwest's Net Billed Projects — Net Billing Agreements" and "Bonneville's 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 Project Agreement, but excluding payments to the United States Treasury and (3) payments to the United States Treasury.

For further information, see "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 "BONNEVILLE FINANCIAL OPERATIONS — Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

FLOW OF FUNDS

The City covenants that it will pay, or cause to be paid, into the Conservation Project Revenue Fund held by the City, as promptly as practicable after receipt, all of the Conservation Revenues (other than the Conservation Revenues and other amounts expressly required or permitted by the Bond Ordinance to be credited to, or deposited in, any other fund or account); provided that Bonneville shall pay Debt Service directly to the Trustee for deposit into the Bond Fund, and not to the Conservation Project Revenue Fund, as provided in the Project Agreement. The Conservation Revenues shall be applied and used only for the following purposes and in the following order of priority:

First, to the Interest Account, up to an amount sufficient to cause the amount on deposit therein to be equal to the amount required to pay interest on the Bonds on the next interest payment date and then to pay City Payments pursuant to a Derivative Product on the next payment date therefor;

Second, to the Serial Bond Principal Account, up to an amount sufficient to cause the amount on deposit therein to be equal to the amount required to pay the installment of principal next coming due on the Bonds, and to the Term Bond Principal Account, up to an amount sufficient to cause the amount on deposit therein to be equal to the amount required to pay the Sinking Fund Requirement next coming due in the next fiscal year on all Term Bonds;

Third, to the reserve account, if one is established, in the amount set forth in the ordinance establishing such account;

Fourth, to any issuer of a credit enhancement for the Bonds, up to an amount sufficient to reimburse such issuer for any amount drawn thereunder plus interest thereon; and

Fifth, after all the above payments and credits have been made, Conservation Revenues may be used for any of the following purposes: (i) for transfer to any other fund or account created by the Bond Ordinance; (ii) for the purchase of any Bonds; (iii) to pay any subordinated indebtedness of the Conservation Project; or (iv) for any lawful corporate purpose of the City relating to the Conservation Project.

NO RESERVE ACCOUNT

There is no reserve account securing the repayment of the Bonds.

ADDITIONAL BONDS

The City has no current plans to issue any Future Parity Bonds, although if Bonneville and the City decide to continue the Conservation Project beyond the initial phase, Future Parity Bonds may be issued to finance the costs of such continuation or to refund the 2003 Bonds. The Bond Ordinance permits the issuance of Future Parity Bonds payable from Conservation Revenues on a parity with the Bonds upon compliance with the following conditions:

1. That when such Future Parity Bonds are issued there is no deficiency in the Bond Fund or in any of the accounts therein and no Event of Default has occurred and is continuing; and

2. There shall be on file a certified copy of the Supplemental Ordinance authorizing the issuance of such Future Parity Bonds; and

3. Bonneville shall have approved the issuance of the Future Parity Bonds; and

4. Debt Service on the Future Parity Bonds is payable by Bonneville under the Project Agreement; and

5. There shall be on file an opinion of Bond Counsel that the Future Parity Bonds are validly issued and constitute an enforceable and binding obligation of the City, except as such enforceability may be limited by laws affecting the rights of creditors or equitable principles.

With the consent of Bonneville, the City may enter into Derivative Products under which its payment obligations are on a parity with the Bonds. See APPENDIX B —"SUMMARY OF THE BOND ORDINANCE — Additional Bonds."

COVENANTS

For certain covenants of the City, see APPENDIX B —"SUMMARY OF THE BOND ORDINANCE — Covenants."

DESCRIPTION OF THE 2003 BONDS

DESCRIPTION

The 2003 Bonds will be dated their date of delivery to the initial purchaser thereof and will be issued in the aggregate principal amount of $17,065,000. The 2003 Bonds will mature on the dates and in the principal amounts, and will bear interest at the respective rates, as shown on the cover page of this Official Statement. The 2003 Bonds will be issued as registered bonds in multiples of $5,000 within a single maturity and will be in a book-entry only system, initially registered in the name of Cede & Co., as nominee for The Depository Trust Company ("DTC"), New York, New York. See APPENDIX D —"BOOK-ENTRY SYSTEM." Interest on the 2003 Bonds will be paid on December 1, 2003, and semiannually thereafter on each June 1 and December 1 to maturity. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

BOND REGISTRAR

The principal of, interest on, and redemption premium of, if any, the 2003 Bonds are payable by the Trustee, currently U.S. Bank National Association, Portland, Oregon (the "Bond Registrar"). For so long as the 2003 Bonds remain in a "book-entry only" transfer system, the Bond Registrar will make such payments to DTC, which, in turn, is obligated to remit such principal and interest to the DTC participants for subsequent disbursement to the Beneficial Owners of the 2003 Bonds as further described in APPENDIX D —"BOOK-ENTRY SYSTEM."

The City and Bonneville have appointed U.S. Bank National Association, a national banking association organized under the laws of the United States, to serve as Trustee. The Trustee is to carry out those duties assignable to it under the Ordinance. Except for the contents of this section, the Trustee has not reviewed or participated in the preparation of this Official Statement and assumes no responsibility for the contents, accuracy, fairness or completeness of the information set forth in this Official Statement or for the recitals contained in the Ordinance or the Bonds, or for the validity, sufficiency, or legal effect of any of such documents.

The Trustee has not evaluated the risks, benefits, or propriety of any investment in the Bonds and makes no representation, and has reached no conclusions, regarding the value or condition of any assets or revenues pledged or assigned as security for the Bonds, or the investment quality of the Bonds, about all of which the Trustee expresses no opinion and expressly disclaims the expertise to evaluate.

Additional information about the Trustee may be found at its website at http://www.usbank.com/corporatetrust. The U.S. Bank website is not incorporated into this Official Statement by such reference and is not a part hereof.

NO REDEMPTION

The 2003 Bonds are not subject to redemption prior to their stated dates of maturity.

OPEN MARKET PURCHASES

The City has reserved the right to purchase the 2003 Bonds in the open market at any price with the consent of Bonneville.

TRANSFER AND REGISTRATION

The 2003 Bonds will be transferable by their Registered Owners only upon the due completion of a written instrument of transfer and upon their surrender, cancellation and reissuance to the new Registered Owner by the Bond Registrar. The Bond Registrar will maintain the Bond Register containing the name and address of the Registered Owner of each 2003 Bond and the principal amount and number of such 2003 Bonds held by each Registered Owner. Transfers of the 2003 Bonds by the Beneficial Owners shall be made in the manner described in APPENDIX D —"BOOK-ENTRY SYSTEM."

PROCEDURE IN THE EVENT OF REVISIONS OF BOOK-ENTRY TRANSFER SYSTEM

If the City is unable to retain a qualified successor to DTC or the City has determined that it is in the best interest of the beneficial owners of the 2003 Bonds not to continue the book-entry system of transfer, the City shall execute, authenticate and deliver at no cost to the Beneficial Owners of the 2003 Bonds or their nominees, 2003 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2003 Bonds shall be payable upon presentment and surrender thereof at the principal office of the Bond Registrar, interest on the 2003 Bonds will be payable by check or draft mailed to the persons in whose names such 2003 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date, and the 2003 Bonds will be transferable as described above; provided, however, if so requested in writing by the Registered Owner of at least $1,000,000 principal amount of 2003 Bonds, interest will be paid by wire transfer on the due date to an account with a bank located in the United States.

DEBT SERVICE REQUIREMENTS

Upon issuance of the 2003 Bonds, the City will not have any other debt of the Conservation Project. Debt service on the 2003 Bonds is set forth below.

Year	Principal Amount	Interest	Total Annual Debt Service
2003	$ 1,120,000	$ 362,557	$ 1,482,557
2004	1,150,000	706,765	1,856,765
2005	1,215,000	649,265	1,864,265
2006	1,265,000	588,515	1,853,515
2007	1,310,000	550,565	1,860,565
2008	1,380,000	485,065	1,865,065
2009	1,445,000	416,065	1,861,065
2010	1,505,000	358,515	1,863,515
2011	1,555,000	298,315	1,853,315
2012	1,625,000	247,000	1,872,000
2013	1,705,000	166,850	1,871,850
2014	1,790,000	81,600	1,871,600
TOTAL	$ 17,065,000	$ 4,911,077	$ 21,976,077

THE CITY

The City of Tacoma, the county seat of Pierce County (the "County"), is located in the west-central part of the State near the southern tip of Puget Sound. It is the third largest city in the State with a 2002 population of 194,900. The City is located 32 miles south of Seattle and 28 miles northeast of Olympia, the state capital. The City was incorporated in 1880 and utilizes the Council-Manager form of government which is administered by a City Council under the Constitution and laws of the State and the City Charter. The Council is composed of a Mayor and eight Council members, five of whom are elected from districts which have been apportioned according to population. The three remaining positions are "at-large" positions, nominated and elected City-wide. The Council member positions are four-year terms with overlapping terms to allow for the election of four new Council members every two years. The Mayor is elected City-wide for a four-year term and is the presiding officer of the Council. Council members, including the Mayor, can serve no more than ten consecutive years as a member of the Council, Mayor, or combination thereof.

The City Council appoints a City Manager who is the chief administrative officer of the City government and who serves at the pleasure of the City Council. The City Manager is responsible to the Council for the administration of all departments of the City with the exception of the Department of Public Utilities. The City Manager has the power to appoint department heads.

The City Manager appoints a Finance Director who supervises the financial affairs of the City including the Department of Public Utilities. The Finance Director is responsible for operating a general accounting system for the City in conformity with generally accepted accounting principles and practices, supervising the purchasing activities of all departments and the receipt, custody and disbursement of all City funds and money. He also supervises the preparation and monitoring of the biennial budget which provides adequate provisioning for the servicing of debt and provides for anticipated revenues to meet the estimated costs of expenditures. The budget is presented to the City Council for their review, approval and final adoption. Under the operating procedures of the City, the Finance Director is responsible for administering the payment of principal and interest on all bonds issued by the City.

THE DEPARTMENT OF PUBLIC UTILITIES — TACOMA POWER

GENERAL

The City Charter provides for a Department of Public Utilities (the "Department") to be governed by a five-member Public Utility Board (the "Board"). The Department consists of Tacoma Power, Tacoma Water, and Tacoma Rail. The Board is responsible for general utility policy, and its members are appointed by the City Council. The Department's budget is presented to the Board for review and approval and then forwarded to the City Council for approval and inclusion in the City's budget.

The Board appoints the Director of Utilities, who is the chief executive officer of the Department and serves at the pleasure of the Board. The Director, with the concurrence of the Board, has the power to appoint division superintendents. The City Charter provides that the revenues of utilities owned and operated by the City may not be used for any purposes other than the ongoing operations of the utilities and payment of debt service on utility debt. The funds of any utility may not be used to make loans to or purchase the bonds of any other utility, department or agency of the City. Certain matters relating to utility operations, such as system expansion, issuance of bonds and fixing of utility rates and charges, are initiated and executed by the Board, but also require formal City Council approval.

Tacoma Power is organized into five business units: Generation; Power Management; Transmission and Distribution; Click! Network; and Energy Services. Tacoma Power, which served an average of approximately 154,000 retail (metered) customers in 2002, is one of the largest publicly-owned utilities in the Pacific Northwest. In 2002, it had approximately 776 employees and operating revenues of approximately $288 million. Tacoma Power was formed in 1893 when the City purchased the water and light utility properties of the former Tacoma Water and Light Company. In 1912, the City constructed its first hydroelectric generating facility on the Nisqually River. Since that time it has acquired generating capacity to meet the growing needs of its customers through a variety of arrangements. City-owned hydroelectric generating projects include Alder and LaGrande on the Nisqually River; Cushman No. 1 and No. 2 on the Skokomish River; Mayfield and Mossyrock on the Cowlitz River; and Wynoochee on the Wynoochee River. Tacoma Power acquires its power from a diverse mix of resources. The resource mix varies slightly from year to year depending upon available water resources and equipment maintenance schedules. Tacoma Power is a statutory preference customer of Bonneville. The City's existing power sales contract with Bonneville expires in 2011.

The following table displays selected operating and financial data regarding Tacoma Power as of December 31, 2002.

Selected Operating and Financial Data
Calendar Year 2002

Average Number of Retail Customers	154,000
Operating Revenues	$ 287,819,610
Gross Investment in Utility Plant	$ 954,380,420
Net Investment in Utility Plant	$ 647,097,763
Total Current Assets	$ 101,625,004
Long-Term Debt	$ 460,513,500

SERVICE TERRITORY

Tacoma Power's service area consists of a 180 square mile area, including the entire 43 square miles comprising the City. Tacoma Power provides electric service within its service area and indirectly serves other portions of the Tacoma metropolitan area through sales to McChord Air Force Base, Fort Lewis Military Reservation, the Town of Ruston and several other customers.

MANAGEMENT

Brief descriptions of the backgrounds of key officials of the Department, Tacoma Power and the City follow.

Mark Crisson, Director of Utilities, assumed his position in 1993. He originally joined the Department in 1975 and served Tacoma Power for eight years in the Power Management Section. In 1983, he left the Department to become the Northwest Power and Public Affairs Manager for Martin Marietta and its successor in interest, Commonwealth Aluminum. In 1985, he was named executive director of Direct Service Industries, Inc., an organization representing the large industrial users of power served directly by Bonneville. In 1987, he returned to Tacoma Power as Superintendent. Mr. Crisson received a B.A. in applied engineering from the U.S. Naval Academy and an M.B.A. from Pacific Lutheran University.

***Steven J. Klein**,* Superintendent, assumed his position in 1993. Engineering career experiences include a private consulting practice and employment with Boeing Computer Services prior to joining the Department. He was hired by the Department in 1978 and has worked in both the Engineering and Power Management Sections of Tacoma Power. Mr. Klein became Tacoma Power's Power Manager in 1988. He has been active in regional groups such as the Public Power Council, Pacific Northwest Utilities Conference Committee, and the Public Generating Pool, serving on many committees and boards of directors. He attended Western Washington University and the University of Washington, receiving a B.S. in electrical engineering.

***Steve Marcotte**,* Director of Finance, joined the City's Finance Department in 1992 as Assistant Finance Director, and was appointed City Treasurer in 1996. Mr. Marcotte was appointed as Acting Finance Director in August 2002 and City Finance Director in September 2002. Mr. Marcotte earned his B.A. in accounting from the University of Washington and an M.B.A. from Pacific Lutheran University.

RATES

The Public Utility Board establishes electric rates for Tacoma Power, subject to approval by the City Council. Tacoma Power's rates and charges are not subject to the jurisdiction and control of the Washington Utilities and Transportation Commission or FERC. With certain exceptions, rates must be set to include a 3.873% tax Tacoma Power pays on its gross revenues to the State of Washington prior to debt service, and a 6.0% (8.0% for Click! Network) tax Tacoma Power pays on gross revenues to the City subordinate to debt service.

CONSERVATION

Tacoma Power offers energy conservation programs that provide the utility with a significant low-cost energy resource. These programs have been pursued because Tacoma Power recognizes that conservation will reduce its load growth and, therefore, its need to acquire power to serve that load growth. Tacoma Power intends to pursue conservation programs which are less expensive and more cost-effective than either constructing new generating facilities or increasing power purchases from other sources. Conservation-related savings have come from a variety of energy uses, including industrial processes and motor usage, heating, ventilating, air conditioning and lighting. Since their inception in the early 1980's, Tacoma Power's conservation programs have produced an estimated 53 aMW of energy savings at a cost of approximately $150 million, a little more than half of which was provided by Bonneville under a series of conservation funding contracts with the utility, including the Project Agreement.

In 1994, Tacoma Power and Bonneville entered into the Project Agreement, which specified the terms under which Bonneville would provide reimbursement to Tacoma Power. See APPENDIX E —"SUMMARY OF THE PROJECT AGREEMENT." The 1994 Bond proceeds were used to finance the initial phase of the Conservation Project for the purpose of developing cost-effective conservation resources. Under the Project Agreement, Bonneville is obligated to pay debt service on the 2003 Bonds, from the Bonneville Fund, whether or not the Conservation Project is terminated, operating or operable. The Project Agreement was the final such contract between Tacoma Power and Bonneville during the 1990's; Bonneville retreated from funding conservation programs during the late 1990's. Bonneville has once again developed funding mechanisms for some conservation programs for the power sales contract period that began in October 2001.

Tacoma Power continues to implement conservation and low-income energy services programs, supporting where possible regional efforts that offer opportunities to collectively impact the marketplace for energy efficient products and services. As part of that effort, Tacoma Power has had a position on the board of directors of the Northwest Energy Efficiency Alliance, a regional entity that Bonneville and the utilities of the Northwest created specifically to help expand the availability and use of energy efficient technologies.

BONNEVILLE POWER ADMINISTRATION

The information in this section has been furnished to the City by Bonneville for use in this Official Statement. Such information is not to be construed as a representation by or on behalf of the City or the Underwriters. The City 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 2003 Bonds, Bonneville will certify to the City that the information in this section, as well as information pertaining to Bonneville contained elsewhere in this Official Statement, 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 Official Statement 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 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, and from several non-federally owned and operated projects including the Columbia Generating Station. 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"), including Tacoma Power, for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to about six 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 2002 payment responsibility to the United States Treasury in full and on time. For more information, see "BONNEVILLE FINANCIAL OPERATIONS — Order in Which Bonneville's Costs Are Met."

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, including cash payments relating to the 2003 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under federal statutes Bonneville may make payments to the United States Treasury only from net proceeds: all cash payments of Bonneville, including cash payments relating to the 2003 Bonds 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. Prices declined in fiscal year 2002, although they have risen somewhat 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 and Power Rates for Fiscal Years 2002-2006

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, as hereinafter described, expired. 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 eight 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 resources and contract purchases, which was estimated at the time to be roughly 8000 average megawatts. 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 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 or will occur 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, are roughly equal to its expected firm load obligations in fiscal years 2004 through 2006 and that Bonneville may have somewhat more firm resources than firm loads for the remainder of fiscal year 2003, depending on the month. Bonneville therefore believes that it will not have to make substantial additional Augmentation Purchases, if any, to meet its Subscription loads through at least fiscal year 2006, subject to changes in contracted loads or generation from Federal System generating resources, and subject to the receipt of power under Augmentation Purchases and other power purchase and related agreements. If contracted loads, especially those of DSIs, drop from current contract levels (after taking into account load reduction agreements), Bonneville could have a firm energy surplus in fiscal years 2004-2006.

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 Rate Proposal"). The 2002 Final Power Rate Proposal is comprised of an initial filing with FERC for "base rates" and a subsequent filing with FERC setting forth certain rate level adjustment mechanisms.

The proposed "base rates" are subject to three intra-rate-period rate level adjustments that are triggered upon the occurrence of specified circumstances. The base rates proposed by Bonneville 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 adjustment mechanisms has had the effect of raising Bonneville's rates substantially. 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.

The second rate level adjustment, the Financial Based Cost Recovery Adjustment Clause ("FB-CRAC"), provides one-year adjustments in rate levels in addition to the LB-CRAC. The FB-CRAC is intended to increase rate levels 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. The amount of revenues Bonneville can obtain under the FB-CRAC is limited to a maximum of between about $90 million and $115 million per fiscal year, depending on the fiscal year in which the FB-CRAC adjustment is used.

The third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause ("SN-CRAC"), enables Bonneville to increase rate levels in order to recover costs on a temporary basis 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.

As described below, rate level increases under the LB-CRAC and FB-CRAC are currently in effect. Bonneville also has initiated actions that will lead to the formal process necessary to possibly increase rate levels under the SN-CRAC. Some Subscription contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms. 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 Rate Proposal."

FERC granted interim approval of the 2002 Final Power Rate Proposal in September 2001 and Bonneville awaits a final order from FERC approving such rates. 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 Rate Proposal."

Bonneville's Fiscal Year 2002 Financial Results

While Bonneville had positive net revenues of $9.5 million in fiscal year 2002, an increase of approximately $347 million over fiscal year 2001, Bonneville estimates it had an operating loss of about $308 million after excluding the positive net revenue effects of extending the 2002 maturities of Energy Northwest net billed program debt under the Debt Optimization Proposal.

Through separate series of "net billing agreements" among Bonneville, numerous electric utility customers of Bonneville and Energy Northwest--a joint operating agency organized under the laws of the State Washington--Bonneville secures over $6 billion in Energy Northwest obligations issued in respect of two now-terminated nuclear generating stations and one operating nuclear generating station. Under the Debt Optimization Proposal, Bonneville and Energy Northwest extended and will extend the average maturities of certain portions of such debt. This has provided and is expected to provide Bonneville with cash flow flexibility to advance the amortization of Bonneville's Federal debt. See "Bonneville Financial Operations — Debt Optimization Proposal."

The debt restructuring increased cash flow to Bonneville in fiscal year 2002, thereby enabling Bonneville to make planned prepayments and planned amortization ahead of schedule of about $266 million in bonds issued by Bonneville to the United States Treasury and appropriated repayment obligations to the United States Treasury. The low net revenues in fiscal year 2002 occurred despite a power rate level increase of over 40 percent over prior rates for similar service, on average during fiscal year 2002. The rate level increase applicable in fiscal year 2002 was made under the LB-CRAC, which is designed for the limited purpose of recovering only the direct costs of power purchases and load reductions under identified contracts Bonneville entered into to meet the 3200-3300 megawatt load increment Bonneville assumed under the Subscription Strategy. The LB-CRAC was not designed to and does not assure recovery of all of Bonneville's costs. The two semi-annual net LB-CRAC adjustments in fiscal year 2002 were about 46 percent and 39 percent of base rates, respectively.

Several developments affected Bonneville's financial results in fiscal year 2002. The main reason for the low net revenues was lower than expected revenues from seasonal surplus energy sales. A substantial portion of Bonneville's power sales revenues, in some years up to 25 percent or more, is derived from the sale of seasonal surplus hydroelectric energy. Bonneville's 2002 Final Power Rate Proposal for the five years beginning October 1, 2001, is based on certain assumptions regarding expected revenues from the sale of seasonal surplus energy. In making seasonal surplus energy revenue projections to support the rate proposal, Bonneville assumed average hydroelectric generation and used price forecasts finalized in May 2001, at a time when prevailing West Coast market prices for electric power were about 20.0 cents per kilowatt-hour. Bonneville's rate case projections assumed that the average price it would receive in fiscal year 2002 for seasonal surplus sales would be about 5.7 cents per kilowatt hour. Contrary to these forecasts, prevailing West Coast wholesale energy prices declined, resulting in Bonneville's obtaining between about 2.0 to 2.5 cents per kilowatt-hour for its seasonal surplus energy in fiscal year 2002.

In addition, although Columbia River Basin precipitation levels in fiscal year 2002 returned from the historically low levels of fiscal year 2001 to the average levels upon which the forecasts in the rate case are based, actual hydroelectric generation was below average, primarily as a result of the effects of refilling reservoirs. In addition, spring runoff conditions resulted in Bonneville's having to sell more than expected amounts of seasonal surplus energy during periods of the year when prices typically are, and in fact were, relatively low. As a consequence of the foregoing factors, Bonneville's discretionary power sales revenues were roughly $670 million lower in fiscal year 2002 than Bonneville forecast in the final stages of developing the 2002 Final Power Rate Proposal.

The lower than average hydroelectric generation and lower than forecast prices also led to a lower than expected realization in fiscal year 2002 of United States Treasury repayment credits for certain fish and wildlife costs incurred by Bonneville. Bonneville receives such credits, which it counts as revenues, under section 4(h)(10)(C) of the Northwest Power Act. A portion of these expenses is for power purchases made by Bonneville that are attributable to the effects of hydroelectric system constraints for the benefit of fish. If power prices decline, the credits Bonneville obtains for such expenditures also decline. Other factors that contributed to Bonneville's 2002 financial results were increased costs from the agreements with Regional IOUs to settle Bonneville's Residential Exchange obligations and increases in other O&M expenses. 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."

As a result of the financial performance in fiscal years 2001 and 2002, Bonneville ended fiscal year 2002 with financial reserves of about $188 million. By contrast, Bonneville's financial reserves for the fiscal years ending September 30, 2000 and September 30, 2001 were about $811 million and $625 million, respectively. 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.

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

Fiscal Year 2003 Financial Developments

The precipitation and snowpack conditions in the Columbia River Basin, which to a great degree determine the amount of hydroelectric power the Federal System can produce, are at very low levels this fiscal year. March 2003 forecasts prepared outside of, but relied on by, Bonneville indicated that January 2003 through July 2003 runoff in the Columbia River Basin as measured at the Dalles Dam may be about 75 percent of average. Therefore, Bonneville may have only about 80-85 percent of the seasonal surplus hydroelectric generation that Bonneville would expect under average water conditions.

In view of Bonneville's fiscal year 2002 financial results, continuing, lower-than-forecast revenues from discretionary sales of electric power, and increasing costs in several areas, Bonneville has taken a number of steps to assure that its revenues are adequate to meet its costs through the remainder of the rate period. First, with indications in early calendar year 2002 that revenues from discretionary power sales would be lower than previously forecasted, Bonneville began reducing its costs substantially. It has continued to do so in fiscal year 2003. Through expense reductions, deferrals and other actions, Bonneville expects to improve its Power Business Line financial health by $350 million in aggregate over the fiscal year 2003-2006 period. Bonneville continues to explore additional cost reductions and deferrals.

Second, Bonneville triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2003. This rate level adjustment will allow 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 has 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. In view of forecasts for the end of fiscal year 2003, Bonneville expects that the FB-CRAC will again be employed in fiscal year 2004, having roughly the same effect on rates and revenue, as is the case in fiscal year 2003. 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 rate for the second six months of the fiscal year.

Third, in February 2003, Bonneville notified its customers that it would initiate the formal rate procedures to potentially increase rate levels under the SN-CRAC. Under the SN-CRAC, Bonneville may adjust power rates an indeterminate amount to recover its costs if Bonneville forecasts a 50 percent or greater probability that it will miss a scheduled payment to the United States Treasury or other party in the then current fiscal year. Bonneville has concluded that there is a 74 percent probability that it would not meet in full its scheduled fiscal year 2003 payments to the United States Treasury.

On March 13, 2003, Bonneville published its initial proposal for the SN-CRAC rate level adjustment. The initial proposal calls for a three-year variable SN-CRAC adjustment with a cap limiting the amount of revenues that can be collected each year under the adjustment. The SN-CRAC adjustment would be structured much like the FB-CRAC adjustment, to be triggered when "accumulated net revenues" fall below identified thresholds. Like the FB-CRAC adjustment, the proposed SN-CRAC adjustment would be set annually in August 2003, 2004 and 2005 on the basis of third quarter financial reports for the related fiscal year, would take effect at the beginning of the next fiscal year, and would remain in effect for the subsequent twelve months. Under the initial proposal, the amount of revenues derived thereunder would be capped at about $470 million per year. In general, "accumulated net revenues" would be measured by the accumulated annual differences, in each fiscal year of the remaining years of the five-year rate period, between accrued revenues and expenses of Bonneville's Power Business Line.

The initial proposal for the SN-CRAC rate level adjustment is designed to recover an expected value of about $340 million to $370 million for each of the three fiscal years in which it is proposed to be in effect. Bonneville estimates that the proposed rate level increase under the initial proposal would average about 15.7 percent of current power rate levels.

The final SN-CRAC adjustment to be proposed by Bonneville will be determined in the formal rate setting process and will be influenced by changes in forecasts, projections and rate design. In proposing a rate level increase under the SN-CRAC, Bonneville expects, among other things, that it will receive lower price levels for discretionary power sales and lower revenues from such sales than Bonneville forecast in the final phases of developing the 2002 Final Power Rate Proposal. The final SN-CRAC proposal will also depend on many other factors including updated financial information, customer input on rate design and the exercise by Bonneville of its judgment about the appropriateness of various rate level increases. The final SN-CRAC proposal could differ, perhaps substantially, from the initial proposal.

Bonneville's long standing goal has been to set rates that achieve an 88 percent probability over five years of meeting its annual United States Treasury payment responsibility in full. Bonneville expects that it will not use this standard in developing the SN-CRAC adjustment. Since Bonneville expects to reserve the ability to adjust rate levels under the SN-CRAC again if the revenues from the first adjustment under the SN-CRAC provision prove inadequate, using a multi-year Treasury payment probability may be less meaningful to Bonneville in setting an SN-CRAC adjustment. Bonneville also believes there is a probability that it will employ a flexible SN-CRAC level adjustment that would vary by reference to periodic financial performance or cost indicators and without additional rate proceedings. Such a feature would also render using a multi-year United States Treasury payment probability goal less meaningful to Bonneville in setting an SN-CRAC adjustment.

Assuming an SN-CRAC adjustment in the 15-16 percent range over the current base rate levels and expected rate level adjustments in fiscal year 2004 under the FB-CRAC and LB-CRAC, Bonneville's average power rates would increase from 3.0 to 3.4 cents per kilowatt hour for the last half of fiscal year 2003 to about 3.2 to 3.6 cents per kilowatt hour during the first six months of fiscal year 2004, without transmission and depending on type of service. In total, such adjustments 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.

Several of Bonneville's customers and customer groups have filed separate suits in the Ninth Circuit Court challenging Bonneville's decision to initiate 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 have been met. The petitioners have not sought expedited review by or injunctive relief from the court in this matter.

Some of the cost reductions and deferrals and the commencement in October 2002 of the rate level increase under the FB-CRAC have impacts in fiscal year 2003. Nonetheless, based on Bonneville's updated quarterly review dated as of May 2003, Bonneville estimates that if current forecasts of costs, streamflows and discretionary power sales are realized, Bonneville would have net revenues of about negative $28 million in fiscal year 2003. This calculation excludes $356 million in positive net revenue arising from debt management actions under the Debt Optimization Proposal. The fiscal year end net revenue projection also excludes about $20 million in non-cash, mark-to-market accounting adjustments under the Financial Accounting Standards Board Statement of Accounting Standard No. 133. These forecasted results also incorporate a total of about $85 million in recently effected one time improvements to cash flows arising from (i) arrangements with Energy Northwest to apply funds from a settlement with a paying agent of certain original Net Billed Bonds to pay current Net Billed Project costs, and (ii) the use of surety bonds in lieu of reserve funds for certain series of Net Billed Project Bonds. In addition to the foregoing events, the May 2003 updated forecast reflects somewhat improved views of Columbia River basin precipitation levels, power marketing conditions and expense levels relative to prior quarterly forecast of anticipated fiscal year end net revenues. Given the many variables and assumptions upon which such forecasts are based, actual net revenues could differ substantially from those indicated in such forecasts.

Notwithstanding the possibility that Bonneville could have negative net revenues in the current fiscal year, and in view of the relatively low fiscal year 2003 starting reserve balance of $188 million, Bonneville intends to manage its finances to assure that the fiscal year 2003 ending reserve level balance will not be lower than between $100 million and $200 million. The possible financial tools Bonneville may rely on to assure adequate reserves to meet cash flow needs in early fiscal year 2004 include, among other items: (i) deferring all or a portion of planned early repayments and amortization of about $315 million in bonds issued by Bonneville to the United States Treasury and appropriations repayment obligations by Bonneville to the United States Treasury at the end of fiscal year 2003 in great part under the Debt Optimization Proposal, (ii) seeking access to short-term borrowing with the United States Treasury under Bonneville's existing borrowing authority, or (iii) deferring scheduled interest and/or principal payments to the United States Treasury, meaning planned payments to the United States Treasury as scheduled under applicable repayment criteria in contrast to the advance amortization payments described in clause (i). Whether and the extent to which Bonneville will rely on the foregoing financial tools will depend on financial performance through the remainder of fiscal year 2003. On the basis of its most recent quarterly review of May 2003, Bonneville now expects that it is much less likely to rely on short-term borrowing from the United States Treasury, deferral of early amortization under the Debt Optimization Proposal, or deferrals of Bonneville's United States Treasury repayments to meet its fiscal year end reserve level needs than Bonneville anticipated when it issued its quarterly report of March 2003.

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 2003-2006 will be at or near average market prices for such period based on similar power products. Bonneville believes that its Subscription Power rates will still 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.

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 2003."

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 estimates that in Operating Year 2003, the Federal System, including firm energy purchases, is capable of producing about 10,300 average megawatts of firm energy.

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.

While Bonneville markets most of its energy on a firm basis, 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.

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 dry 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, 2002, Slice customers purchased from Bonneville, for their requirements, an aggregated 22.63 percent proportionate interest of the output of the Federal System. This purchase includes firm power and what would otherwise be seasonal surplus energy from the Federal System in the same proportion. See “Power Business Line — Power Marketing in the Period After Fiscal Year 2001 — Preference Customer Loads.”

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. 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 2003

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 2003, 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 2003(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	1941	33	5,325	3,041	2,378	1,872
Hungry Horse	1952	4	323	129	101	77
Other Bureau Projects(6)		15	225	163	156	130
Total Bureau of Reclamation Projects		52	5,873	3,333	2,635	2,079
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,129	1,622	1,334	1,047
John Day	1968	16	1,888	1,376	1,065	768
The Dalles including Fishway(7)	1957	24	2,074	1,077	839	602
Bonneville including Fishway	1938	20	752	562	523	357
McNary	1953	14	935	711	697	551
Lower Granite	1975	6	485	439	323	212
Lower Monumental	1969	6	595	411	272	214
Little Goose	1970	6	752	440	321	209
Ice Harbor	1961	6	471	314	199	97
Libby	1975	5	533	297	223	166
Dworshak	1974	3	343	219	190	125
Other Corps Projects(8)		20	396	294	268	223
Total Corps of Engineers Projects		153	11,353	7,762	6,254	4,571
Total Bureau of Reclamation and Corps of Engineers Projects		205	17,226	11,095	8,889	6,650
Non-Federally-Owned Projects						
The Columbia Generating Station(9)	1984	1	1,150	877	877	877
Other Non-Federal Projects(10)		18	96	181	169	167
Total Non-Federally-Owned Projects		19	1,246	1,058	1,046	1,044
Total Bonneville Contract Purchases(11)		N/A	2,440	2,560	2,560	2,560
Total Federal System Resources		224	20,912	14,713	12,495	10,254

Source: 2001 Pacific Northwest Loads and Resources Study, Bonneville, October 2002.

(1) Operating Year 2003 is August 1, 2002 through July 31, 2003.

(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), 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), Green Springs (1960), Hills Creek (1962), Lookout Point (1954) and Lost Creek (1975).
(9) Columbia Generating Station has a scheduled maintenance outage, which will affect its energy output.
(10) Other Non-Federal Projects include the following hydroelectric and other projects: Mission Valley's Big Creek (1981), Lewis County PUD's Cowlitz Falls (1994), the City of Idaho Falls' Idaho Falls Project (1982), 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 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, a share of Energy Northwest's Nine Canyon 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.

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 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 the 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 the U.S. Department of Energy's ("DOE") 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 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.

Bonneville, Energy Northwest, EFSEC and DOE have negotiated a proposed agreement concerning site restoration for Projects 1 and 4. Bonneville, DOE, and Energy Northwest have signed the proposed agreement and await a signature by an authorized official representing EFSEC. The proposed agreement would require that Bonneville fund site remediation of Projects 1 and 4 in return for a commitment on a level of site remediation that is less expensive than maximum level of site restoration considered by EFSEC. The total cost of the level of remediation under the proposed agreement has been estimated at $45 million (calendar year 2003 dollars).

With the exception of near-term remediation compatible with reuse (approximately $3 million to $4 million expended within 24 months of approval of the remediation plan by EFSEC), assuming execution and delivery of the agreement by all parties, Bonneville would probably defer the remediation obligation for about 20 years as permitted by the proposed agreement, leaving the sites and the structures available for potential reuse.

To meet its proposed financial commitment for remediation, Bonneville expects to place 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 (including Tacoma Power) within the Region, are entitled to a statutory preference and priority (the "Public Preference") in the purchase of available Federal System power. These customers are eligible to purchase power at Bonneville's "Priority Firm Rate" (or, "PF Rate") for most of their loads, and as a class are Bonneville's principal customer base. Under the 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.

Some Regional public bodies served by Regional IOUs are now seeking to form public body utilities to qualify as Preference Customers and obtain priority access to electric power from Bonneville. These public bodies include municipalities and port districts. Under the Subscription process, Bonneville received conforming requests from and signed contingent contracts with four such entities. Under Subscription, about 75 average megawatts of firm power at the Priority Firm rates were reserved for, and are now provided to, such new entities.

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" and "BONNEVILLE FINANCIAL OPERATIONS — Historical Federal System Financial Data."

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. See "BONNEVILLE LITIGATION — M-S-R Public Power Agency, *et al.*, v. Bonneville Power Administration."

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 have resulted in concerns by energy suppliers that the Cal-ISO may not be 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.

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 $90 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 has initiated two separate 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 both proceedings.

In the first proceeding, FERC is reviewing 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. In this proceeding, FERC has concluded that unjust and unreasonable pricing in fact occurred. FERC bifurcated the proceeding and conducted a hearing before an Administrative Law Judge (ALJ) in March 2002 to determine a pricing structure that approximates a competitive market. FERC, through the ALJ, conducted a second hearing in August 2002 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. On December 12, 2002, the ALJ issued Proposed Findings related to the March and August phases of the hearing. The Proposed Findings are subject to review by FERC. The exact amount of any refund liability and a determination of who owes what to whom will be determined in a compliance filing that is yet to be scheduled. Despite the issuance of the Proposed Findings, Bonneville cannot predict with any accuracy the amount of refund liability against Bonneville because the actual calculation must be determined through the settlement computer systems of the Cal-ISO and Cal-PX. However, based upon prior calculations of refund liability and the impact of the Proposed Findings on these earlier calculations, Bonneville believes that the amount of any refunds determined by FERC against Bonneville would be substantially less than the unpaid amounts owed to Bonneville by the Cal-PX and the Cal-ISO. Under prior rulings by FERC, this should result in a net payment owed to Bonneville.

In the second proceeding, FERC is reviewing 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. FERC has indicated that if it were to find that power sellers exacted unjust and unreasonable prices during this period, FERC would undertake a subsequent proceeding to determine refund liability.

FERC held a hearing in early September 2001 in this proceeding. On September 24, 2001, the presiding judge 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 presiding 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. FERC has not yet ruled on the presiding judge's recommendations.

While Bonneville is a participant in the foregoing refund proceedings, Bonneville is taking 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 nonjurisdictional utilities' petitions. Several nonjurisdictional utilities, including Bonneville, have filed appeals in Federal appellate court.

In a related matter, on February 13, 2002, FERC announced that it is initiating an investigation by FERC staff into 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. The order directing the investigation does not specify the remedial actions that FERC may implement or attempt to implement in the event it were to conclude that price manipulation or undue influence over prices in fact occurred. See "— Effect on Bonneville of the Enron Bankruptcy" immediately below.

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. Assuming Bonneville's estimate of its refund exposure is correct, Bonneville's aggregate refund exposure would still be less than the amount owed to Bonneville by the Cal-ISO and Cal-PX.

Effect on Bonneville of the Enron Bankruptcy

On December 2, 2001, Enron Corp. and a number of its subsidiaries, including Enron Power Marketing Incorporated ("EPMI"), filed for bankruptcy protection under federal bankruptcy laws. At the time, EPMI was Bonneville's second largest electric power trading counterparty and Bonneville and EPMI had between them about one hundred separate transactions for forward sales and purchases of electric power. The parent, Enron Corp., guaranteed performance of all of the contracts Bonneville has with EPMI.

At the time of the bankruptcy filing, the aggregate amount of forward power transactions between Bonneville and EPMI exceeded 400 megawatts annually on average over the five years ending September 30, 2006. Under certain of the transactions, Bonneville agreed to sell power to EPMI and under other transactions, Bonneville agreed to purchase power from EPMI. Bonneville estimates that the average net obligation that EPMI was obligated to provide at the time of the bankruptcy filing was about 60 megawatts of power per year to Bonneville over such five year period. Bonneville has no contracts with EPMI beyond September 30, 2006.

Subsequent to the bankruptcy filing, Bonneville terminated two of the longer term contracts for the sale of power to EPMI. Following the termination of these two contracts, EPMI's net delivery obligation to Bonneville under the remaining power contracts is about 200 megawatts on average through September 2006. Bonneville has not terminated any other transactions with EPMI. In addition, Bonneville estimated that with respect to the remaining contracts it would have a net payment obligation to EPMI in virtually all months through September 30, 2006.

While EPMI was unable to meet some off peak delivery obligations to Bonneville in December 2001, it has since met its power receipt and delivery obligations to Bonneville. Bonneville currently has no accounts receivable due from EPMI.

Bonneville, as a part of the U.S. Government and through the U.S. Department of Justice, filed a notice of appearance in the bankruptcy proceeding.

On March 20, 2003 the Enron Bankruptcy Court, the U.S. District Court for the Southern District of New York, approved in advance a proposed settlement of all claims relating to all power sales and purchase agreements between Bonneville and Enron. On April 25, 2003, Bonneville and Enron entered into an agreement to settle all claims between them relating to settlement of all claims relating to all power sales and purchase agreements between Bonneville and Enron. Under the settlement, Bonneville has agreed to cause to be paid to Enron a single lump sum payment of approximately $99 million, which reflects a discount in Bonneville's favor in the mark-to-market value of the remaining terms of the power transactions. The settlement agreement further provides that all of the claims and obligations of the parties with respect to the foregoing transactions are extinguished.

The lump sum payment to Enron will be provided by the United States Treasury from the Judgment Fund. The Judgment Fund is a continuing, indefinite appropriation by Congress for the payment of certain claims and settlements involving the United States and certain of its agencies and instrumentalities. Bonneville is obligated to reimburse the United States Treasury for such payments and Bonneville expects that the reimbursement terms with the United States Treasury will provide that Bonneville make full repayment, together with interest, by the end of December 2006. This repayment period coincides roughly with the original final payment term of the related Enron power transactions.

The anticipated schedule of Bonneville's reimbursement payments to the United States Treasury would be substantially less than the net payments Bonneville would have otherwise made to Enron had the power transactions continued to their original expiration dates. In addition, Bonneville estimates that it has a surplus of firm power through fiscal year 2006. Thus, Bonneville believes that the extinguishment of Enron's obligation to sell power to Bonneville will not have an adverse effect on Bonneville's ability to meet its contracted load obligations through fiscal year 2006.

Portland General Electric Company ("Portland General"), which is a Regional IOU as described herein and a contract party with Bonneville in several transactions, is a wholly owned subsidiary of Enron Corp. Portland General has not filed for bankruptcy protection. While Portland General has indicated that it has taken steps, with the consent of the bankruptcy court, to insulate itself and its assets from the Enron bankruptcy, Bonneville cannot provide any assurance whether such steps will in fact protect Portland General in the bankruptcy proceeding. As part of the bankruptcy proceeding Enron Corp. has solicited proposals for the purchase of Portland General. Bonneville continues to monitor Portland General's creditworthiness.

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 defines Bonneville's power-marketing program for the next five to ten years and seeks 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. 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 other than the Federal System hydroelectric projects, existing contract purchases and projects, such as the Columbia Generating Station, the capability of which Bonneville has previously acquired. 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 Pacific Northwest Electric Power and Conservation Planning Council (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 ESA constraints have major implications for Bonneville's resource acquisition strategy. Given long-term load placement uncertainty, 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 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 revenue requirements. In dry years, Bonneville's revenue requirement would increase as it would be forced to spend a significant amount of money for short-term purchases to meet loads. In wet years, purchase requirements can be significantly reduced as Bonneville will meet more of its load with non-firm hydroelectric power. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation.

Bonneville's short-term purchase resource strategy is complemented by two other opportunities. First, Bonneville is adding environmentally preferred, so-called "green power" resources. The bulk of these additional purchases is likely to be from wind projects because of their relatively low cost and the expectation that the new wind projects can become operational within 12-18 months of a decision to proceed. While it is possible that Bonneville could acquire up to about 1000 megawatts of wind resources, the amount of wind energy resources that Bonneville ultimately purchases is uncertain and will depend on 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 green power resources, Bonneville has agreed to acquire 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 has contracted to purchase 49.9 megawatts from a geothermal project under construction in northern California and is considering additional purchases from renewable energy resources. Second, Bonneville will encourage electric power conservation measures by providing a 0.5 mills per kilowatt hour rate discount to its customers that implement conservation measures and/or renewable resource projects. The discounts should result in about $40 million per year (during the fiscal year 2002-2006 rate period) being spent on conservation and renewable resource initiatives by customers. In addition, Bonneville is purchasing about 100 average megawatts of conservation savings through fiscal year 2006 as part of its 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 has relied primarily on and will rely 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 it is 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 declines 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. See "— Power Marketing in the Period After Fiscal Year 2001."

Fish and Wildlife

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 $419 million in fiscal year 2002. In addition, Bonneville estimates that it had about $12 million in Foregone Power Revenues. The total of the preceding costs is within the range of such costs provided under the 1998 Guidance, as described in "— 1998 Guidance Regarding Fish and Wildlife Costs," and within the range assumed in the 2002 Final Power Rate Proposal.

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 2002 was about $430 million.

<u>2000 Biological Opinion</u>. 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 Rate Proposal 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. In calendar years 2003, 2005 and 2008, NOAA Fisheries is expected to issue reports 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 first such report, which is to be completed in the fall of 2003, is expected to evaluate overall implementation of the reasonable and prudent alternative measures. The reports in year 2005 and year 2008 are expected to evaluate 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. Under the 2000 Biological Opinion, NOAA Fisheries indicates 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. 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 and $38.4 million in fiscal years 2001 and 2002, respectively. Bonneville currently projects that the recoupments will be about $101 million in fiscal year 2003, but the actual amount will depend to a great degree on actual hydroelectric generation results and market prices for electric energy through the remainder of the fiscal year. 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.

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. The conditions governing access to the Contingency Fund were not met in fiscal year 2002, leaving an unused balance of about $78 million in the Contingency Fund. Bonneville is currently forecasting low water conditions in fiscal year 2003 and believes that it will obtain access to the Contingency Fund this fiscal year. Nonetheless, it remains uncertain whether the criteria for access to the Contingency Fund will be met this fiscal year.

1998 Guidance Regarding Fish Costs. In September 1998, the Clinton Administration announced Fish and Wildlife Funding Principles ("1998 Guidance"). The 1998 Guidance permits Bonneville to continue to receive the previously agreed to annual 4(h)(10)(C) recoupments. The 1998 Guidance also provides that Bonneville will set rates for the five-year rate period beginning fiscal year 2002 to achieve no lower than an 80% probability of meeting its federal repayment responsibilities in full over such period, assuming a range of fish and wildlife cost scenarios.

Bonneville employed these criteria in developing the Final 2002 Power Rate Proposal. See "— Power Marketing in the Period After Fiscal Year 2001."

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 Rate Proposal. 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.

In response to financial developments over the past two years, Bonneville requested, and the Council has agreed, to a budget level of $139 million for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's 2002 Program. The Council is evaluating Bonneville's request that the fiscal year 2002 budget level remain in effect over the three remaining years of the five-year period beginning October 1, 2001. This level is approximately the same as was assumed in Bonneville's 2002 Final Power Rate Proposal.

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 has contracted to sell all of its 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, including Tacoma Power. 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.

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.

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 direct sales of 1000 average megawatts of firm power to the Regional IOUs at Bonneville's Residential Load Rate ("RL Rate"). The RL Rate is proposed to be at a level similar to Bonneville's lowest available requirements service rate, the PF Rate. In addition, Bonneville originally agreed to provide Regional IOUs with cash payments for the Exchange Value of 900 average megawatts of firm power. In general, the Exchange Value is based on 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. Bonneville expects that its aggregate payments to Regional IOUs for Exchange Value will amount to about $148 million per year on average over the five-year rate period. In fiscal year 2002, this amount was $144 million.

Through subsequent 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 $240 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. See "BONNEVILLE LITIGATION — Residential Exchange Settlement Litigation." These payments, whether discounted or not, are recovered under the LB-CRAC in the 2002 Final Power Rate Proposal.

In addition, through the exercise by three other Regional IOUs of conversion rights in their Residential Exchange Settlement Agreements, Bonneville subsequently obtained about 125 average megawatts in additional load reductions throughout the five-year rate period. Under these conversions, Bonneville's power sales obligations converted into obligations to provide cash payments of about $10 million per year in aggregate throughout the five-year rate period. As a consequence of the foregoing actions, Bonneville's Subscription power sales obligation to Regional IOUs is now limited to a single power sales agreement with one Regional IOU. The amount of power Bonneville provided under this agreement was about 225 average megawatts in fiscal year 2002, and it increases to about 260 average megawatts in fiscal year 2006.

The foregoing payments to and by Bonneville under the Residential Exchange Settlement Agreements are or could be affected by the application of at least one of the three intra-rate period rate level adjustments included in the 2002 Final Power Rate Proposal. For example, the 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 to be reduced in the event Bonneville employs a rate level adjustment under the SN-CRAC. In addition, since the Exchange Value is subject to certain changes by reference to the RL Rate, Bonneville's payments for the Exchange Value may be reduced if the RL Rate level is increased due to the triggering of the SN-CRAC.

For the five-year period after fiscal year 2006, Bonneville expects to meet its Residential Exchange settlement obligations in full through the actual provision of about 2200 average megawatts of electric power to the Regional IOUs. Nonetheless, Bonneville negotiated default provisions for the payment of monetary benefits in lieu of power to the extent that Bonneville becomes unable to provide the full 2200 average megawatts of power in such period.

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.

DSI Loads. 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 power marketing 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 is currently selling almost no power to DSIs, either because Bonneville agreed to buy back some of its sales obligations and/or to suspend some of the DSI purchase obligations, or because the DSI has curtailed its operations. In addition, two of the aluminum company DSIs have filed for bankruptcy protection. One such company, Kaiser Aluminum, subsequently rejected its Bonneville power contract in bankruptcy, thereby terminating Bonneville's obligation to sell any power under the contract. Bonneville has filed a proof of claim in the proceeding. See "LITIGATION — Kaiser 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 that are not yet in arrears 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.

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. If contracted loads, especially those of DSIs, drop from current contract levels (after taking into account load reduction agreements), Bonneville could have a firm energy surplus in fiscal years 2004-2006.

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 proposed base power rates because they under-recover Bonneville's costs and Bonneville publishes a record of decision that adopts higher 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. Bonneville awaits a final order from FERC approving the 2002 Final Power Rate Proposal.

Risk Management. Bonneville believes that its ability to recover power costs 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 cost of power Bonneville purchases to meet commitments that exceed Federal System resources and 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 Rate Proposal. On June 29, 2001, Bonneville filed its 2002 Final Power Rate Proposal with FERC, proposing power rates for the five years beginning October 1, 2001. On September 28, 2001 FERC granted interim approval of such rates pending final review. Bonneville awaits a final order by FERC approving the proposal. The rate proposal includes proposed base rates applicable to the varying types of Subscription agreements and certain intra-rate period adjustments that will increase or decrease power rate levels depending on certain conditions. The base rate levels proposed by Bonneville 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 rate proposal also includes 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 2002 Final Power Rate Proposal is comprised of the initial rate filing with FERC proposing the "base rates" and a subsequent supplementary rate filing with FERC that amends the initial proposal by proposing the LB-CRAC, FB-CRAC and SN-CRAC.

The proposed 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 cost 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 proposed FB-CRAC is designed to restore, on a forecasted basis, Bonneville's financial reserves to fiscal year-end reserve levels ("Reserve Targets") of $300 million in fiscal years 2002 and 2003 and $500 million in each of fiscal years 2004-2006. 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. A rate increase under the FB-CRAC continues through the end of the applicable fiscal year.

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 proposed 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 Rate Proposal, Bonneville determines 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 aggregate purchase obligations to a substantial degree. The remaining 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. For the second six months of the rate period, the LB-CRAC was set at about 39% of the base rates, and for the third six-month period (beginning October 1, 2002), the LB-CRAC was set at about 32% of base rates. Bonneville has notified its customers that the LB-CRAC for the six months beginning April 1, 2003, will be about 39% of base rates. Bonneville expects that the LB-CRAC adjustments for the remainder of the rate period will be in roughly the same range as has been the case to date.

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 is roughly 11% of base rates for those contracts to which the FB-CRAC applies. Bonneville expects that the FB-CRAC will trigger again for fiscal year 2004, although, under the terms of the FB-CRAC, such a determination will be made some time after the end of the third quarter of this fiscal year.

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 will be about 3.0-3.4 cents per kilowatt hour, excluding transmission.

On February 7, 2003, Bonneville issued a letter notifying its customers that the conditions triggering the SN-CRAC have been met and that Bonneville has initiated the formal rate procedures to possibly increase rate levels thereunder. Bonneville has concluded that there is approximately a 26 percent probability that it would meet in full its scheduled fiscal year 2003 payments to the United States Treasury.

On March 13, 2003, Bonneville published its initial proposal for the SN-CRAC rate level adjustment. The initial proposal calls for a three-year variable SN-CRAC adjustment with a cap limiting the amount of revenues that can be collected each year under the adjustment. The SN-CRAC adjustment would be structured much like the FB-CRAC adjustment, to be triggered when thresholds of accumulated net revenues fall below identified thresholds. Like the FB-CRAC adjustment, the proposed SN-CRAC adjustment would be set annually in August 2003, 2004 and 2005 on the basis of third quarter financial reports for the related fiscal year, would take effect at the beginning of the next fiscal year, and would remain in effect for the subsequent twelve months. Under the initial proposal, the amount of revenues derived under the SN-CRAC would be capped at about $470 million per year. In general, "accumulated net revenues" would be measured by the accumulated annual differences, in each fiscal year of the remaining years of the five-year rate period, between accrued revenues and expenses of the power business line.

The initial proposal for the SN-CRAC rate level adjustment is designed to recover an expected value of about $340 million to $370 million for each of the three fiscal years in which it is proposed to be in effect. Bonneville estimates that the rate level increase under the initial proposal would average about 15.7 percent of power rate levels currently in effect. While the final SN-CRAC adjustment proposed by Bonneville will be influenced by various projections and forecasts, Bonneville expects that it will reserve the ability to adjust rate levels under the SN-CRAC again if the revenues from the first adjustment under the SN-CRAC provision prove inadequate. Bonneville's initial proposal for the SN-CRAC rate level adjustment proposes an SN-CRAC adjustment that varies on the basis of financial performance indicators.

Assuming an SN-CRAC adjustment in the 15-16 percent range over expected adjustments in fiscal year 2004 under the FB-CRAC and LB-CRAC, Bonneville's average Subscription power rates would be about 3.2-3.6 cents per kilowatt hour in the first six months of fiscal year 2004, without transmission and depending on whether it is for Block Sales or Requirements Products.

In proposing a rate level increase under the SN-CRAC, Bonneville expects, among other things, that it will use lower forecasts of price levels for discretionary surplus power sales and lower forecasts of revenues from such sales than Bonneville used in the final stages of developing the 2002 Final Power Rate Proposal.

The procedures for implementing the SN-CRAC require that Bonneville develop an initial proposed adjustment, conduct evidentiary hearings before a hearings officer, prepare an administrative record setting forth a final proposal and the rationale therefor, and submitting the record and final proposal to FERC for review. Bonneville expects to submit the final proposal and record of decision to FERC in July 2003. The final SN-CRAC proposal will depend on many factors including updated financial information, customer input on rate design and the exercise by Bonneville of its judgment about the appropriateness of various rate level increases. The final SN-CRAC proposal could differ, perhaps substantially, from the initial proposal.

Rate Proposal 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. With the exception of most months through the rest of fiscal year 2003, Bonneville does not expect to have substantial firm power to market during the remainder of the five year rate period because of Subscription sales. 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.

In 1997, the State of Montana, in which a small number of cooperatively owned Net Billing Participants conduct business, enacted legislation providing for competitive retail markets. The legislation enables such cooperatives voluntarily to permit retail choice in their service territories. Under the legislation, if a Montana Net Billing Participant were to provide access over its distribution facilities to competitors, it would nonetheless be entitled to collect "transition costs" on a non-avoidable basis, subject to the obligation to mitigate transition costs. Transition costs are defined to include "existing commitments or obligations incurred before May 2, 1997." Under the Montana legislation, the ability of a Participant to collect transition charges is not limited in duration. Also, the Montana Net Billing Participants retain discretion to determine the extent and nature of their transition costs. To date, only one Montana electric power cooperative has chosen to permit full retail choice for all customers in its service territory. This cooperative has not experienced load loss, apparently due to the favorable rates it is able to offer its customers.

In 1999, the State of Oregon enacted a retail competition law. The Oregon law specifically preserves the ability of Net Billing Participants located in Oregon to charge rates for use of distribution facilities to recover their obligations under their Net Billing Agreements. The implementation provisions of open access contained in this law were delayed with the passage of a subsequent law in 2001.

Most of the Net Billing Participants serve retail loads in Washington. In 1997, the state legislature considered but did not enact proposals to implement competitive retail power markets. No similar bills have since been introduced in the legislature and Bonneville believes it is very unlikely that a restructuring bill will be introduced in the near future. While Bonneville believes that retail competition legislation in Washington, if enacted, would preserve the Participants' obligations under the Net Billing Agreements, Bonneville cannot predict whether the state will enact retail competition or the terms thereof should such legislation be enacted.

Several Participants serve loads in Idaho. The Idaho State legislature has not introduced legislation that would establish retail competition.

TRANSMISSION BUSINESS LINE

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 the Bonneville 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.

Bonneville has not added significant capacity to its transmission system since 1987. Bonneville is currently studying additional possible transmission investments to ease congestion, integrate new generation and provide a reliability margin on the transmission system. Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $425 million a year over the four fiscal years commencing October 1, 2002. The transmission system is operated at or near capacity and congestion is developing in some areas of the system. Load growth on the system has been about 1.8% a year and transmission use has grown about 2% a year. In addition, Bonneville expects to interconnect between 2000 and 5000 megawatts of proposed and new generation to the transmission system over the next four years. 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 will require 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. With regard to congestion and reliability investments, Bonneville expects to use its United States Treasury borrowing authority, although it is possible that Bonneville may use other sources of financing.

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 2002 transmission and ancillary services rates were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. Such rates are effective through September 30, 2003. In January 2003, Bonneville published its initial transmission and ancillary services rate proposal for fiscal years 2004-2005. Under the initial proposal Bonneville would increase such rates by 1.5 per cent. Bonneville expects to issue a final proposal and submit it to FERC for review in the spring of 2003. The final proposal could differ from the initial proposal.

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 the formation of a nonprofit RTO (to be named RTO West) for a region composed of Washington, Oregon, Idaho, Utah, Nevada, Montana and western Wyoming. Under the evolving 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. Until December 2011 or such other transition period approved by FERC, costs for the use of Bonneville's transmission facilities would be recovered through Bonneville's own "company rates." The draft operating agreement also provides that Bonneville would continue to set its costs and billing determinants, which would be applied by RTO West to derive company rates that recover Bonneville's costs from its own loads. 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 April 2001, 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 to 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.

FERC also 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 July 2001, FERC reversed itself in part and agreed to accept a proposal to allocate risk among the transmission owners and RTO West. FERC did not change its decision not to use the tariff to limit the liability of RTO West and transmission owners for damages to transmission users from interruptions in tariff service and bodily injury claims. 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. Nonetheless, 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 July 2002, FERC issued a new Notice of Proposed Rulemaking proposing to modify the Order 888 *pro forma* tariff for an interim period, and proposing a new standardized network access transmission service for independent transmission companies or RTOs and a new standardized market design for wholesale power participants (SMD NOPR). In September 2002, FERC approved a majority of the Phase 2 filing, including the company rate concept, an 8-year transition period, voluntary conversion of existing transmission contracts to RTO West Tariff service, and a modified congestion management proposal, FERC rejected the proposal that the proposed operating agreement provisions would govern in the event of a conflict with the RTO West Tariff. FERC directed the Filing Utilities to submit a memorandum of understanding providing for cooperation between the proposed western RTOs for resolving interregional issues. FERC also urged the Filing Utilities, in collaboration with stakeholders, to strengthen the oversight of the RTO West market monitoring unit regarding market mitigation measures to prevent the exercise of market power due to market design flaws or unusual market conditions. The RTO West market monitoring unit would report directly to FERC.

The Filing Utilities continue to work on the issues raised by FERC in its September 2003 order, the Filing Utilities' Phase 3 proposal, and the remaining complex issues that must be resolved to obtain agreement of the parties and obtain FERC approval of the proposal. Bonneville's current expectations are that RTO West would not begin operating transmission assets until calendar year 2006 or 2007.

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. While no specific grounds for the review are identified in the petition, Bonneville expects that petitioners will reassert their concerns that FERC has improperly refused to assess the costs and benefits of the RTO West proposal and that Bonneville lacks authority to join RTO West.

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, and requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates. 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 Net Billed Bonds. However, Bonneville believes that any major electric industry restructuring affecting its obligations with respect to the Net Billed Bonds would require federal legislation. It is also possible that parties may propose terms that could, if implemented, have an adverse impact on the tax-exempt status of the Net Billed Bonds. Bonneville would oppose any proposal that would have an adverse impact on the tax-exempt status or the credit structure of the Net Billed Bonds.

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.

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, 2002, Bonneville had repaid $4.5 billion of principal of the Federal System investment and has $4.5 billion principal amount outstanding.

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. The law also restricts the amount of permanent borrowing authority Bonneville may use in fiscal year 2003 to $531 million. Bonneville believes that this limitation will have no material effect on Bonneville's finances in fiscal year 2003.

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.77 billion of bonds were outstanding as of September 30, 2002. 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.

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, 2002, the interest rates on the outstanding bonds ranged from 3.05% to 8.55% with a weighted average interest rate of approximately 6.01%. 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: 45 years for transmission facilities and 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 involves the extension of the final maturity of certain Columbia bonds 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 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 revenues Bonneville has available to pay other obligations, including payments with respect to the 2003 Bonds.

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 2002 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.056 billion in fiscal year 2003, approximately $266 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury and certain appropriated repayment obligations. 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.

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, including cash payments relating to the 2003 Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all cash payments of Bonneville, including cash payments relating to the 2003 Bonds 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 would pay 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.

In November 1996, Bonneville and the Bureau agreed to a five-year direct funding agreement, beginning in fiscal year 1998, for roughly $40 million in annual operations and maintenance expense at the Bureau's Federal System facilities. In December 1997, Bonneville and the Corps entered into a ten-year agreement for direct funding that is expected to result in roughly $100 million per year in direct payments by Bonneville, beginning in fiscal year 1999. In September 2000, Bonneville and the Fish and Wildlife Service entered into a one-year agreement for direct funding of power related operations and maintenance costs of the Lower Snake River Compensation Plan Program ("Snake River Plan"), a fish and wildlife program funded in part by Bonneville. In January 2001, Bonneville and the Fish and Wildlife Service entered into a five-year agreement for direct funding of power related operations and maintenance costs of the Snake River Plan. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2002 were $51 million for the Bureau, $132 million for the Corps, and $15 million for the Fish and Wildlife Service.

Direct funding differs from historical practice under which (i) the Corps and the Department of Interior obtained specific appropriations from Congress for Federal System operations and maintenance, with relatively little influence from Bonneville as to the nature or amount of any such expense and (ii) Bonneville repaid the appropriations, with interest, at the end of the fiscal year for which the appropriations were made, which repayments were otherwise subject to deferral if Bonneville had inadequate amounts in the Bonneville Fund. Under Bonneville's statutory priority of payments, Bonneville's repayments of amounts appropriated to the Corps and the Department of Interior for Federal System operations and maintenance expense are made annually after the payment of Bonneville's non-federal payment obligations in the related fiscal year. As with Bonneville's other repayments to the Treasury, repayments of appropriated operations and maintenance expense would be subject to deferral if Bonneville were to have insufficient amounts in the Bonneville Fund to meet its non-federal payments.

Bonneville believes that, in contrast to historical 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 is concerned that its decisions to manage and economically hedge 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, which includes Bonneville's third party debt service obligations with regard to the Net Billed Bonds. 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 the 2003 Series C, D and E Bonds (the "Related Bonds") expected to be issued at the same time as the Series 2003-A Bonds and the Series 2003-B 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 will be 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 Services 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 2000 through 2002 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information was extracted from audited financial statements or accounting records supporting the audited financial statements. 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) for the fiscal year ended September 30, 2002 are included as Appendix A-1 hereto and Bonneville's unaudited quarterly report for the six months ended March 31, 2003 is included as Appendix A-2 hereto.

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

Fiscal year ending September 30,	2002	2001	2000
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Publicly-owned utilities [1]	$ 1,797,496	$ 939,362	$ 934,270
Aluminum industry	58,454	420,694	363,454
Investor-owned utilities	377,789	700,836	649,449
Other power sales	1,293	972	38,578
Sales outside the Northwest Region [2]	638,261	1,084,077	652,221
Total Sales of Electric Power	2,873,293	3,145,940	2,637,972
Transmission and other revenues [3]	660,436	1,132,729	402,197
Total Operating Revenues	3,533,729	4,278,669	3,040,169
Operating Expenses:			
Bonneville O&M [4]	775,077	530,618	506,878
Purchased Power	1,286,867	2,291,961	624,882
Corps, Bureau and Fish & Wildlife O&M [5]	198,055	184,922	162,621
Non-Federal entities O&M — net billed [6]	167,026	208,839	193,085
Non-Federal entities O&M — non-net billed [7]	35,566	30,719	32,942
Total Operation and Maintenance	2,462,591	3,247,059	1,520,408
Net billed debt service	213,919	455,397	535,460
Non-net billed debt service	16,256	21,818	25,139
Non-Federal Projects Debt Service [8]	230,175	477,215	560,599
Federal Projects Depreciation	335,205	323,314	319,942
Residential Exchange [9]	143,983	68,082	63,593
Total Operating Expenses	3,171,954	4,115,670	2,464,542
Net Operating Revenues	361,775	162,999	575,627
Interest Expense:			
Appropriated Funds	352,551	317,213	315,826
Long-term debt	151,997	129,159	115,052
Capitalization Adjustment [10]	(67,356)	(68,784)	(67,474)
Allowance for funds used during construction	(57,892)	(45,679)	(28,754)
Net Interest Expense	352,300	331,909	334,650
Cumulative Effect of SFAS 133 [11]		(168,491)	
Net Revenues/(Expenses)	$ 9,475	$ (337,401)	$ 240,977
Total Sales — average megawatts (Net of Residential Exchange Program)	11,225	10,302	11,361

(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 non-firm 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.
(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 Financial Accounting Standards Board Statement of Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville recorded a cumulative-effect adjustment of $168 million 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 $9.5 million in fiscal year 2002, 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 (from $354 million to $38 million) 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 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 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. 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 2002 were approximately $3.2 billion, a decrease of $944 million, or 22%, 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.

For fiscal year 2001, Bonneville had negative net revenues of approximately $337 million, a substantial decline of approximately $578 million from net revenues in fiscal year 2000. Total operating revenues increased over fiscal year 2000 by approximately $1.2 billion, despite a very low water year, primarily due to a tripling in market prices for discretionary power sales from the previous year, and a ten-fold increase in fish credits under the Northwest Power Act, as described below. These extremely high market prices translated into an increase of $432 million, or 66%, in revenues from sales outside the Region. In addition, Bonneville remarketed power returned by certain aluminum company DSIs and the remarketing of this returned power increased revenues from the aluminum company DSIs by $57 million, or 16%, in fiscal year 2001. The higher prices for power increased sales revenues from Regional IOUs by $51 million, or 8%. Conversely, power sales revenues from non-aluminum company DSIs declined by approximately $38 million, or 97%, due to decreased power sales to these customers. The $731 million, or 182%, increase over fiscal year 2000 in revenues from transmission and other related services, is due to estimated Treasury repayment credits of $354 million under Section 4(h)(10)(C) of the Northwest Power Act and to Treasury repayment credits of $247 million from the Contingency Fund. Total operating expenses increased by approximately $1.6 billion in fiscal year 2001 over fiscal year 2000. This was in large part due to extremely high market prices for power in the Western markets. Purchased power expenses increased by $1.67 billion, or 267%, due to a 137% increase in the amount of power purchased by Bonneville in response to low water conditions as well as the aforementioned high market prices at which such purchases were made. In addition, Corps, Bureau and Fish and Wildlife Service operations and maintenance expenses increased by $22 million in fiscal year 2001 due to, among other factors, an increased maintenance program at the Corps designed to help increase the availability of generation units and an increase in the power purpose's responsibility for certain costs of Grand Coulee Dam. See "BONNEVILLE FINANCIAL OPERATIONS — The Bonneville Fund" in this Official Statement. Non-Federal entities O & M – net-billed expenses increased by $16 million due to increased operating expenses related to the Columbia Generating Station. However, net-billed debt service decreased by $80 million, or 15%, due to refinancing and restructuring of a portion of the outstanding net-billed debt.

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 7 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,	2002	2001	2000
Total Operating Revenues	$3,533,729	$4,278,669	$3,040,169
Less: Operating Expense[1]	2,408,520	3,130,219	1,421,380
Net Funds Available for Non-Federal Project Debt Service	1,125,209	1,148,450	1,618,789
Less: Total Non-Federal Project Debt Service[2]	230,175	477,215	560,599
Revenue Available for Treasury	895,034	671,235	1,058,190
Amount Paid to Treasury:			
Corps and Bureau O&M[3]	198,055	184,922	162,621
Net Interest Expense[4]	352,300	331,909	334,650
Capitalization Adjustment[5]	67,356	68,784	67,474
Allowance for Funds Used During Construction[4] [6]	15,061	12,479	8,578
Amortization of Principal	505,012	210,127	289,925
Total Amount Allocated for Payment to Treasury[7]	1,137,784	808,221	863,248
Revenues Available for Other Purposes[8]	(242,750)	(136,986)	194,942
Non-Federal Project Debt Service Coverage Ratio[9]	4.9	2.4	2.9
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[10]	1.3	1.2	1.5

(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, including payments with respect to the 1994 Bonds. Non-net billed debt service amounted to $25.1 million, $21.8 million and $16.3 million for fiscal years 2000, 2001 and 2002, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps and Bureau for fiscal years 2000, 2001 and 2002, and to Fish & Wildlife Service for fiscal years 2001 and 2002. 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 2000, 2001 and 2002 were $732 million, $729 million and $1.056 billion, respectively. In fiscal years 2000, 2001 and 2002, respectively, direct payments to the Corps and Bureau for operations and maintenance were included in the amount of (i) $104 million, $117 million and $132 million for the Corps, and (ii) $46 million, $55 million and $51 million for the Bureau. In fiscal years 2001 and 2002, direct payments for Fish & Wildlife Service were $13 million and $15 million, 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) (5)
(Actual Dollars in Thousands)

Fiscal years ending September 30,	2002	2001	2000
Operating Revenues from Publicly-Owned Utilities(2)	$1,797,496	$ 939,362	$ 934,270
Net Billing Obligations:			
Net Billing Credits	610,180	675,938	642,541
Payments in Lieu of Net Billing(3)	(111,329)	57,283	66,992
Net Billing Obligations — Cash	498,851	733,221	709,533
Net Billing Expenditures:			
Net Billed Debt Service	213,919	455,397	535,460
Other Entities O&M — Net Billed	167,026	208,839	193,085
Increase/(Decrease) in Prepaid Expense	117,906	68,985	(19,012) (4)
Net Billing Expenditures — Accrual	$ 498,851	$ 733,221	$ 709,533

(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) Excludes $22.2 million of prepaid expenses not associated with the Net Billed Projects.
(5) While the 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. 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 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. While the mark-to-market figures are subject to change with market volatility, Bonneville and Kaiser have been very close to agreement on what the appropriate calculation should be. A separate issue, however, and one on which there is less agreement is the rate that would be applicable to the Kaiser sales. The current IP rate is subject to rate mechanisms that allow Bonneville to raise rates under certain circumstances. 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 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.

CPN Cascade, Inc., formerly d/b/a CE Newberry, Inc. v. Bonneville Power Administration

In October 2002, CPN Cascade, Inc. filed a petition for review in the Ninth Circuit Court. The petition is styled as a precautionary petition for review to comply with the 90-day statute of limitations contained in the Northwest Power Act.

The subject of the petition is a 48-megawatt geothermal power project that CPN has yet to construct, and power from the project that CPN seeks to sell to Bonneville. Bonneville and CPN have an ongoing dispute over a settlement agreement related to the project and Bonneville's obligations to pay certain funds to CPN Cascade. In July 2002, Bonneville sent a letter to CPN stating that Bonneville believes its obligations under the agreement have been fulfilled or extinguished. CPN disagreed and filed the petition for review alleging that statements made by Bonneville in the July 2002 letter were arbitrary, capricious, an abuse of discretion, and violate the terms of the settlement agreement. If CPN is successful, the court could remand the matter to Bonneville for further consideration.

PacifiCorp v. United States

In September 2002, PacifiCorp, an investor-owned utility, filed an action in the United States District Court for the District of Oregon seeking an order to compel arbitration under the General Transfer Agreement (GTA), a transmission contract between Bonneville and PacifiCorp.

Because of a meter error, PacifiCorp served a Bonneville power load for approximately five months. PacifiCorp is seeking approximately $11 million in damages for this service. It alleges that it provided the service under the GTA and that the dispute is subject to arbitration under that contract.

In November 2002, Bonneville filed its response to PacifiCorp's petition. Bonneville denies that this issue arises under the GTA. Bonneville instead asserts that it is an "inadvertent interchange" of energy, and that under procedures of the Western Electricity Coordinating Council, a reliability organization to which Bonneville and PacifiCorp both belong, PacifiCorp is entitled to return of the power, but not to monetary compensation. Bonneville further asserts that even if the issue arises under the GTA, it is not subject to arbitration under the contract's arbitration clause.

On May 1, 2003, the court granted PacifiCorp's petition to compel arbitration. Bonneville is in the process of analyzing the court's opinion to determine whether to appeal.

Puget Sound Energy Inc. v. United States

In July 1999, Puget Sound Energy Inc., ("Puget"), a Regional IOU, filed a breach of contract claim against the United States in the U.S. Court of Federal Claims ("Claims Court"), alleging that Bonneville overcharged Puget for certain construction costs relating to a segment of the Southern Intertie referred to as the "AC Line." Under an agreement that Bonneville and Puget entered into in 1994, Puget received transmission capacity rights in the AC Line in return for a promise to reimburse Bonneville for certain costs Bonneville incurred in constructing the project. Puget seeks $9.4 million in damages.

Upon a motion filed by Bonneville, the Claims Court transferred the case to the Ninth Circuit Court. The Claims Court ruled that the dispute is a transmission rates matter and that exclusive jurisdiction for such challenges is vested in the Ninth Circuit Court. In January 2001, Bonneville filed a motion with the Ninth Circuit Court to dismiss the transferred case on the grounds that the original complaint was filed after the time permitted for challenging Bonneville's actions in the Ninth Circuit and is therefore time-barred. The court has ruled for Bonneville and has dismissed the case.

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 Claims Court. 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 Claims Court 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 Claims Court on the jurisdictional issue and remanded the Contract Disputes Act matter to the Claims Court.

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.

The briefing schedules have been vacated, the cases have been stayed, and settlement discussions are underway.

5(b)/9(c) Policy Challenge

In July 2000, a number of Bonneville customers filed individual petitions in the Ninth Circuit Court seeking review of Bonneville's policy on determining customer net requirements under sections 5(b) and 9(c) of the Northwest Power Act (the "5(b)/9(c) Policy"). The court subsequently consolidated the petitions into a single proceeding. Among those challenging the policy are individual Preference Customers, two Regional IOUs and a DSI. Intervenors include another Regional IOU, two associations of Preference Customers, an association of industrial electricity customers in the Region and the State of Oregon.

The 5(b)/9(c) Policy is an important component of Bonneville's execution and implementation of the Subscription power sales contracts. Under section 5(b) of the Northwest Power Act, Bonneville is obligated to offer a contract to each requesting Preference Customer and Regional IOU to meet its respective firm loads within the Region, net of the resources used by the utility to serve such loads. In making this determination, Bonneville has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act and section 3(d) of the Regional Preference Act. These sections require that Bonneville reduce the amount of Federal System power Bonneville would otherwise be obligated to supply by the amount of power a requesting customer is exporting from its own resources outside the Pacific Northwest which could have been conserved or otherwise retained by the customer for use in the Pacific Northwest.

Under the 5(b)/9(c) Policy, Bonneville defines the conditions under which a Regional customer may export power out of the Region from its own resources without decreasing the amount of requirements service it may receive from Bonneville.

Bonneville and the petitioners have agreed to a settlement of this litigation. Under the settlement, Bonneville will publish certain clarifications to its 5(b)(9)(c) Policy. In March 2003, the court granted the settlement agreement and dismissed the case.

M-S-R Public Power Agency, *et al*. v. Bonneville Power Administration

In 1999, Bonneville was sued by numerous DSIs, as well as the M-S-R Public Power Agency ("M-S-R"), a power agency established pursuant to the laws of California, in the Ninth Circuit Court. The DSIs and M-S-R sought review of Bonneville's August 30, 1999 "Excess Federal Power" determination. In that determination, Bonneville provided its customers notice of the amount of surplus power Bonneville is authorized to market as excess federal power. Excess federal power is surplus power that Bonneville may sell for up to seven years without the recall constraints that would otherwise apply by reason of the Regional Preference Act. The amount of such power varies based on periodic determinations by Bonneville under its Excess Federal Power Policy. See "POWER BUSINESS LINE — Customers of Bonneville's Power Business Line — Exports of Surplus Power to the Pacific Southwest." These parties asked the court to determine whether Bonneville's determination of the amount of excess federal power for the period August 1999 through July 2009 was in compliance with its contractual or statutory authorities.

In addition, M-S-R filed a petition for review of Bonneville's September 28, 2000 preliminary annual excess federal power determination, as well as Bonneville's September 29, 2000 notification to M-S-R that firm power will likely not be available for sale to M-S-R for the Contract Year that begins on October 1, 2004. On December 19, 2000, Bonneville issued its final Excess Federal Power determination for the year 2000.

On July 11, 2002, the Ninth Circuit Court issued its opinion in this case. The court affirmed Bonneville's action, in part, and remanded the case back to Bonneville in part. With respect to the petition for review filed by petitioner M-S-R, the court upheld Bonneville's actions and found that Bonneville reasonably interpreted its statutory authorities and its power sales contract with M-S-R. However, with respect to the petition for review filed by the DSIs, the court held that Bonneville miscalculated amounts of forecasted Excess Federal Power. As a result, the court vacated Bonneville's 1999 and 2000 Excess Federal Power forecasts, and ordered Bonneville to reissue forecasts consistent with the opinion.

In 2002, Bonneville issued new Excess Federal Power forecasts incorporating the court's rationale. While the new forecasts project a larger deficit of Excess Federal Power, the amount of forecasted Excess Federal Power remains a negative number. Thus, the new forecasts do not have a financial impact on Bonneville. The new forecasts have not been challenged.

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), Puget Sound Energy (a Regional IOU), 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 PNGC and Puget cases were selected for inclusion in the Ninth Circuit Court's mediation program. The case has been stayed and settlement discussions are underway.

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.

California Oregon Intertie (COI) Transmission Dispute

In March 2000, the Transmission Agency of Northern California ("TANC"), a joint-powers agency of the State of California and a participant in transmission facilities in that state, filed an action against Bonneville, the Sierra Pacific Power Co. ("Sierra Pacific"), PacifiCorp, and the Portland General Electric Company in California state court. TANC challenged Bonneville's participation in the interconnection of its federal transmission facilities with facilities owned and operated by Sierra Pacific ("Alturas Interconnection"). TANC alleged the interconnection adversely affects its rights under agreements related to the Pacific Northwest-Southwest AC Intertie ("COI Transmission Line"). The action was removed to the U.S. District Court for the Eastern District of California. TANC's claims against Bonneville include inverse condemnation, trespass, nuisance, conversion and breach of contract. TANC seeks damages in the amount of $23 million.

In November 2000, Bonneville moved to dismiss TANC's complaint on the basis that the Ninth Circuit Court has exclusive jurisdiction over Bonneville in this matter and other grounds. The other named defendants also moved to dismiss TANC's claims on other grounds. In February 2001, the district court dismissed all claims against Bonneville on a determination that the court lacked jurisdiction to review the claims. The court also dismissed all claims against the other defendants. In March 2001, TANC appealed the district court's decision to the Ninth Circuit Court. The Ninth Circuit Court heard argument on this case in February 2002, and affirmed the dismissal in July 2002. TANC then filed a petition for review by the U.S. Supreme Court. The parties await a ruling by the Supreme Court whether to grant review of the case.

TANC's complaint in the foregoing litigation is similar to another Bonneville matter before FERC. In 1998, Sierra Pacific sought approval from FERC for the Alturas Interconnection, which FERC granted. TANC and other California public and private utilities intervened in the proceeding, asserting that the interconnection adversely affected reliability of the COI Transmission Line. In March 2001, the Presiding Administrative Law Judge issued an Initial Decision, which substantially supports Bonneville's position. The Initial Decision is on appeal before FERC and the parties await a decision.

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. Briefing is complete, and oral argument is set for May 6, 2003.

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. Briefs have been filed and parties await a date for oral argument.

Southern California Edison v. Bonneville Power Administration

Southern California Edison ("Southern") filed three separate 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 Southern.

In the first petition for review, Southern challenges Bonneville's decision to convert the contract from a sale of power to an exchange of power. In the second petition for review, Southern challenges a Record of Decision issued by Bonneville in its rate adjustment proceeding. Southern alleges that the rate adjustment violates its power sales contract. In the third petition for review, Southern challenges Bonneville's letter to Southern terminating service under its power sales contract due to Southern'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 Southern has filed administrative claims for relief with Bonneville as an apparent predicate to re-filing its claims in the Court of Federal Claims. In March 2003, SCE re-filed litigation in the Court of Federal Claims on the claim that Bonneville breached the contract by converting it from a power sale to a power exchange.

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. The case has been briefed and oral argument is set for May 6, 2003.

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 has scheduled 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."

The court has remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. To address the court's concern that offsite measures are not reasonably certain to occur, it is possible that NOAA Fisheries 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.

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 NMFS did not include the entire "distinct population segment" which also includes hatchery fish, it acted arbitrarily and capriciously. As a result, the court delisted 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. In addition to the appeal, NMFS received 14 additional petitions from various interest groups to de-list other salmon populations. NMFS has decided to revisit its Hatchery Listing Policy. NMFS has not yet officially proposed its amended Hatchery Listing Policy, and the parties await a ruling on the appeal from the Ninth Circuit Court.

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 has proposed new power rates for the five years beginning October 1, 2002. Bonneville will propose 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.

NO LITIGATION

There is no litigation pending or threatened in any court (local, state or federal) to restrain or enjoin the issuance or delivery of the 2003 Bonds, or questioning the creation, organization, existence, or title to office of the officers of the Department of Utilities, Tacoma Power or the City, the validity or enforceability of the Bonds or the Bond Ordinance or the proceedings for the authorization, execution, sale and delivery of the 2003 Bonds.

TAX EXEMPTION

GENERAL

In the opinion of Preston Gates & Ellis LLP, Seattle, Washington, Bond Counsel, interest on the 2003 Bonds will be excluded from gross income subject to federal income taxation pursuant to Section 103 of the Internal Revenue Code of 1986 (the "Code"), provided the City complies with arbitrage requirements of Section 148 of the Code described in this section under the heading "Continuing Requirements." The 2003 Bonds are not private activity bonds and interest on the 2003 Bonds is not an item of tax preference for purposes of determining alternative minimum taxable income for individuals or corporations under the Code. However, interest on the 2003 Bonds is taken into account in the computation of adjusted current earnings for purposes of the corporate alternative minimum tax under Section 55 of the Code as more fully described in this section under the heading "Certain Federal Income Tax Consequences."

Except as described herein, Bond Counsel expresses no opinion on any federal, state or local tax consequence arising with respect to ownership of the 2003 Bonds.

CONTINUING REQUIREMENTS

Section 148 of the Code has continuing arbitrage requirements that must be met subsequent to the issuance of the 2003 Bonds for the interest on the 2003 Bonds to be, and remain, exempt from regular federal income taxation. These requirements include provisions that prescribe investment yield limitations for the proceeds of the 2003 Bonds and that certain investment earnings be paid on a periodic basis to the federal government. The Bond Ordinance contains covenants of the City to comply with these continuing arbitrage requirements. Bond Counsel has not undertaken to determine (or to inform any person) whenever any action taken (or not taken) or events occurring (or not occurring) after the date of issuance of the 2003 Bonds may affect the tax status of the interest on the 2003 Bonds.

CERTAIN FEDERAL INCOME TAX CONSEQUENCES

The following is a discussion of certain federal income tax matters under the Code. This discussion does not purport to deal with all aspects of federal taxation that may be relevant to particular bond owners. Prospective bond owners, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the 2003 Bonds, as well as any tax consequences arising under the laws of any state or other taxing jurisdiction.

Alternative Minimum Tax on Corporations. Section 55 of the Code imposes an alternative minimum tax on corporations equal to the excess of the tentative minimum tax for the taxable year over the regular tax for such year. The tentative minimum tax is based upon alternative minimum taxable income which is regular taxable income with certain adjustments and increased by the amount of certain items of tax preference. One of the adjustments is a portion (75% for any taxable year beginning after 1989) of the amount by which a corporation's adjusted current earnings exceeds the corporation's alternative minimum taxable income (determined without regard to such adjustment and the alternative tax net operating loss deduction). Interest on tax-exempt obligations, such as the 2003 Bonds, is included in a corporation's adjusted current earnings.

For taxable years beginning December 31, 1997, the corporate alternative minimum tax is repealed for small business corporations that had average gross receipts of less than $5 million for the three-year period beginning after December 31, 1994, and such small business corporations will continue to be exempt from the corporate alternative minimum tax so long as their average gross receipts do not exceed $7.5 million.

Financial Institutions. The Code denies banks, thrift institutions and other financial institutions a deduction for 100% of their interest expense allocable to tax-exempt obligations, such as the 2003 Bonds, acquired after August 7, 1986.

Borrowed Funds. The Code provides that interest paid on funds borrowed to purchase or carry tax-exempt obligations during a tax year is not deductible. In addition, under rules used by the Internal Revenue Service for determining when borrowed funds are considered used for the purpose of purchasing or carrying particular assets, the purchase of obligations may be considered to have been made with borrowed funds even though the borrowed funds are not directly traceable to the purchase of such obligations.

Property and Casualty Insurance Companies. The deduction for loss reserves for property and casualty insurance companies is reduced by 15% of the sum of certain items, including the interest received on tax-exempt bonds, such as the 2003 Bonds.

Social Security and Railroad Retirement Benefits. The Code also requires recipients of certain Social Security or Railroad Retirement benefits to take into account, in determining gross income, receipts or accruals of interest that is exempt from federal income tax, such as the 2003 Bonds.

Branch Profits Tax. Certain foreign corporations doing business in the United States may be subject to a branch profits tax on their effectively connected earnings and profits, including tax-exempt interest on obligations, such as interest on the 2003 Bonds.

S Corporations. Certain S corporations that have subchapter C earnings and profits at the close of a taxable year and gross receipts more than 25% of which are passive investment income, which includes interest on tax-exempt obligations, such as interest on the 2003 Bonds, may be subject to a tax on excess net passive income.

RATINGS

Moody's Investors Service ("Moody's") and Standard & Poor's, a Division of The McGraw-Hill Companies, Inc. ("S&P") have assigned their municipal bond ratings of AA- and Aa1, respectively, to the 2003 Bonds. Such ratings reflect only the views of the rating organizations, and an explanation of the significance of the ratings may be obtained from the rating agencies as follows: Moody's Investors Service, 99 Church Street, New York, New York 10007, (212) 553-0300 and Standard & Poor's, a Division of The McGraw-Hill Companies, Inc., 55 Water Street, New York, New York 10041, (212) 438-7280. There is no assurance that the ratings will continue for any given period of time or that they will not be revised downward or withdrawn entirely by the rating agencies, if, in the judgment of the agencies, circumstances so warrant. Any such reduction or withdrawal of such ratings may have an adverse effect on the market price of the 2003 Bonds.

UNDERWRITING

The Underwriters have agreed, subject to certain conditions, to purchase the 2003 Bonds from the City at the aggregate prices or yields set forth on the cover of this Official Statement less an underwriting discount of $112,799.65 and including a net original issue premium of $1,164,376.40. The Underwriters will be obligated to purchase all of 2003 Bonds if any are purchased. The Underwriters have advised the City that the 2003 Bonds may be offered and sold to certain dealers (including other dealers depositing 2003 Bonds into investment trusts) at prices lower than the initial public offering prices, and the initial public offering prices may be changed from time to time by the Underwriters.

CERTAIN LEGAL MATTERS

All legal matters incident to the authorization and issuance of the 2003 Bonds are subject to the approval of Preston Gates & Ellis LLP, Bond Counsel, Seattle, Washington, whose approving opinion in substantially the forms attached hereto as Appendix C will be delivered to the City and to the Underwriters in connection with the issuance of the 2003 Bonds. Certain legal matters will be passed upon for Bonneville by its General Counsel. Legal matters regarding whether the 2003 Bonds can be sold under the "Blue Sky" laws of certain states, whether the 2003 Bonds are exempt from the registration requirements of the Securities Act of 1933, and whether the Second Supplemental Ordinance must be qualified under the Trust Indenture Act of 1939 will be passed upon for the Underwriters by their counsel, Foster Pepper & Shefelman, PLLC. Any opinion of Underwriters' counsel will be rendered solely to the Underwriters, will be limited in scope, and is not to be relied upon by investors without the prior written consent of such counsel. From time to time, Preston Gates & Ellis LLP serves as counsel to the Underwriters on unrelated transactions and Foster Pepper & Shefelman PLLC serves as counsel to the City on unrelated transactions. Certain legal matters with respect to the City will be passed upon by the City Attorney.

CONTINUING DISCLOSURE UNDERTAKING

In accordance with Section (b)(5) of Securities and Exchange Commission Rule 15c2-12 under the Securities and Exchange Act of 1934, as the same may be amended from time to time (the "Rule"), the City has agreed in the Second Supplemental Ordinance and Bonneville will agree to provide or cause to be provided to each nationally recognized municipal securities information repository ("NRMSIR") and to the state information depository for the State (if one is created) ("SID"), in each case as designated by the Securities and Exchange Commission (the "Commission") in accordance with the Rule, the following annual financial information and operating data for the prior fiscal year:

1. Audited financial statements of the Conservation Project prepared in accordance with generally accepted accounting principles applicable to government entities, with regulations prescribed by the Washington State Auditor pursuant to RCW 43.09.200 (or any successor statute) provided that, if the Conservation System's financial statements are not yet available, the City shall provide unaudited financial statements in substantially the same format, and audited financial statements when they become available. Such annual information and operating data shall be available on or before nine months after the end of the City's fiscal year (commencing in 2004 for the fiscal year ended December 31, 2003). The City's current fiscal year ends December 31. The City may adjust such fiscal year by providing written notice of the change of fiscal year to each then existing NRMSIR and the SID, if any. In lieu of providing such annual financial information and operating data, the City may cross-reference to other documents the City provides to the NRMSIRs and the SID or to the Commission and, if such document is a final official statement within the meaning of the Rule, available from the Municipal Securities Rulemaking Board ("MSRB");

2. Audited financial statements of Bonneville prepared in accordance with generally accepted accounting principles; provided, that if Bonneville's financial statements are not yet available, Bonneville shall provide unaudited financial statements in substantially the same format and audited financial statements when they become available. Bonneville shall provide its financial statements within 180 days after its fiscal year, which currently ends September 30.

The City and Bonneville agree to provide or cause to be provided, in a timely manner, to each NRMSIR or to the MSRB and to the SID, if any, notice of its failure to provide the annual financial information described above on or prior to the date set forth above.

The City further agrees to provide or cause to be provided, in a timely manner, to the SID, if any, and to each NRMSIR or to the MSRB notice of the occurrence of any of the following events with respect to the 2003 Bonds, if material:

- ♦ Principal and interest payment delinquencies;
- ♦ Nonpayment related defaults;
- ♦ Unscheduled draws on debt service reserves reflecting financial difficulties;
- ♦ Substitution of credit or liquidity providers or their failure to perform;
- ♦ Unscheduled draws on credit enhancements reflecting financial difficulties;
- ♦ Adverse tax opinions or events affecting the tax-exempt status of the 2003 Bonds;
- ♦ Modifications to rights of 2003 Bondholders;
- ♦ 2003 Bond calls (other than mandatory sinking fund redemptions);
- ♦ Defeasances;
- ♦ Rating changes; and
- ♦ Release, substitution or sale of property securing repayment of the 2003 Bonds.

The City's and Bonneville's obligations to provide annual financial information and notices of material events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2003 Bonds. Such undertaking, or any provision thereof, shall be null and void if the City and Bonneville (1) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule which require the undertakings, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the 2003 Bonds; and (2) notifies each then existing NRMSIR and the SID, if any, of such opinion and the cancellation of such undertaking.

Notwithstanding any other provision of the Bond Ordinance, the City and Bonneville may amend their undertakings, without the consent of any 2003 Bondholder, with an approving opinion of bond counsel.

The City or Bonneville, as appropriate, will give notice to each NRMSIR or the MSRB, and the SID, if any, of the substance (or provide a copy) of any amendment to its undertaking and a brief statement of the reasons for the amendment. If the amendment changes the type of annual financial information to be provided, the notice also will include a narrative explanation of the effect of that change on the type of information to be provided.

A 2003 Bond owner's or Beneficial Owner's right to enforce the provisions of the City's or Bonneville's undertaking described under this heading shall be limited to a right to obtain specific enforcement of the City's or Bonneville's obligations, and any failure by the City or Bonneville to comply with the provisions of its undertaking shall not be an event of default with respect to the 2003 Bonds. For purposes of this section, "Beneficial Owner" means any person who has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of, any 2003 Bonds, including persons holding 2003 Bonds through nominees or depositories.

PRIOR COMPLIANCE WITH CONTINUING DISCLOSURE UNDERTAKINGS

The City and Bonneville have complied with their prior written undertakings under the Rule.

MISCELLANEOUS

Any statements in this Official Statement involving matters of opinion, whether or not expressly so stated, are intended as such, and are not a representation of fact. This Official Statement is not to be construed as an agreement or contract between the City and the purchasers or owners of any 2003 Bonds.

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APPENDIX A

FEDERAL SYSTEM AUDITED FINANCIAL STATEMENTS FOR THE YEARS ENDED SEPTEMBER 30, 2002 AND 2001

AND

FEDERAL SYSTEM UNAUDITED QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2003

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Report of Independent Accountants

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 and of revenues and expenses, of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2002 and 2001, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2002, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2002, 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, 2002 (Schedule A) is presented for purposes of additional analysis and is 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, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
December 16, 2002

Financial Statements

Statements of Revenues and Expenses

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

	2002	2001	2000
Operating Revenues			
Sales	$ 3,407,404	$ 3,563,182	$ 2,903,735
SFAS 133 mark-to-market	38,354	47,877	—
Miscellaneous Revenues	49,571	66,902	103,251
U.S. Treasury Credits for Fish	38,400	600,708	60,000
Total operating revenues	3,533,729	4,278,669	3,066,986
Operating Expenses			
Operations and maintenance	1,319,707	1,023,180	977,439
Purchased power	1,286,867	2,296,076	633,142
Nonfederal projects (Note 4)	230,175	473,100	560,836
Federal projects depreciation	335,205	323,314	319,942
Total operating expenses	3,171,954	4,115,670	2,491,359
Net operating revenues	361,775	162,999	575,627
Interest Expense			
Interest on federal investment:			
Appropriated funds (Note 3)	258,195	248,429	248,352
Long-term debt (Note 2)	151,997	129,159	115,052
Allowance for funds used during construction	(57,892)	(45,679)	(28,754)
Net interest expense	352,300	331,909	334,650
Net revenues (expenses) before cumulative effect of SFAS 133	9,475	(168,910)	240,977
Cumulative effect of SFAS 133	—	(168,491)	—
Net Revenues (Expenses)	9,475	(337,401)	240,977
Accumulated net (expenses) revenues, Oct. 1	(221,151)	132,810	(108,167)
Irrigation Assistance	—	(16,560)	—
Accumulated net (expenses) revenues, Sept. 30	**$ (211,676)**	**$ (221,151)**	**$ 132,810**

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

	2002	2001
Utility Plant (Notes 1 and 3)		
Completed plant	$ 11,488,047	$ 11,249,158
Accumulated depreciation	(4,052,117)	(3,817,309)
	7,435,930	7,431,849
Construction work in progress	1,200,179	913,670
Net utility plant	8,636,109	8,345,519
Nonfederal Projects (Note 4)		
Conservation	47,733	50,189
Hydro	167,080	170,730
Nuclear	2,127,907	2,116,473
Terminated hydro facilities	29,555	30,245
Terminated nuclear facilities	3,829,269	3,804,312
Total nonfederal projects	6,201,544	6,171,949
Trojan Decommissioning Cost (Note 5)	73,861	69,221
Conservation, net of accumulated amortization of $831,631 in 2002 and $769,221 in 2001 (Notes 1 and 2)	409,571	444,021
Fish and Wildlife, net of accumulated amortization of $129,207 in 2002 and $110,954 in 2001 (Notes 1 and 2)	134,204	146,354
Current Assets		
Cash	235,409	667,306
Accounts receivable	299,040	387,805
Materials and supplies, at average cost	85,107	85,222
Prepaid expenses	285,696	187,149
Total current assets	905,252	1,327,482
Other Assets	151,458	265,984
	$ 16,511,999	**$ 16,770,530**

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2002	2001
Capitalization and Long-Term Liabilities		
Accumulated net expenses (Note 1)	$ (211,676)	$ (221,151)
Federal appropriations (Note 3)	4,595,915	4,647,017
Capitalization adjustment (Note 3)	2,192,400	2,259,756
Long-term debt (Note 2)	2,563,141	2,582,542
Nonfederal projects debt (Note 4)	5,958,538	5,954,490
Trojan decommissioning reserve (Note 5)	63,861	57,221
Total capitalization and long-term liabilities	15,162,179	15,279,875
Commitments and Contingencies (Notes 5 and 6)		
Current Liabilities		
Current portion of federal appropriations	46,687	23,913
Current portion of long-term debt	207,300	106,000
Current portion of nonfederal projects debt	243,006	217,459
Current portion of Trojan decommissioning reserve	10,000	12,000
Accounts payable and other current liabilities	343,425	510,957
Total current liabilities	850,418	870,329
Deferred Credits (Note 1)	499,402	620,326
	$16,511,999	**$16,770,530**

Statements of Changes in Capitalization and Long-Term Liabilities

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

	Accumulated Net Revenues (Expenses)	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2000	**$ 132,810**	**$4,566,011**	**$2,513,200**	**$6,408,865**	**$2,406,847**	**$16,027,733**
Increase in federal appropriations:						
Construction	—	230,388	—	—	—	230,388
Repayment of federal appropriations:						
Construction	—	(125,469)	—	—	—	(125,469)
Capitalization adjustment amortization	—	—	—	—	(68,784)	(68,784)
Irrigation Assistance	(16,560)	—	—	—	—	(16,560)
Increase in long-term debt	—	—	260,000	—	—	260,000
Repayment of long-term debt	—	—	(84,658)	—	—	(84,658)
Net decrease in nonfederal projects debt	—	—	—	(60,658)	—	(60,658)
Repayment of nonfederal projects debt	—	—	—	(176,258)	—	(176,258)
Trojan decommissioning reserve	—	—	—	—	(9,086)	(9,086)
Net expenses	(337,401)	—	—	—	—	(337,401)
Balance at Sept. 30, 2001	**$ (221,151)**	**$4,670,930**	**$2,688,542**	**$6,171,949**	**$2,328,977**	**$15,639,247**
Increase in federal appropriations:						
Construction	—	168,583	—	—	—	168,583
Repayment of federal appropriations:						
Construction	—	(196,911)	—	—	—	(196,911)
Capitalization adjustment amortization	—	—	—	—	(67,356)	(67,356)
Increase in long-term debt	—	—	390,000	—	—	390,000
Repayment of long-term debt	—	—	(308,101)	—	—	(308,101)
Net increase in nonfederal projects debt	—	—	—	258,775	—	258,775
Repayment of nonfederal projects debt	—	—	—	(229,180)	—	(229,180)
Trojan decommissioning reserve	—	—	—	—	4,640	4,640
Net revenues	9,475	—	—	—	—	9,475
Balance at Sept. 30, 2002	**$ (211,676)**	**$4,642,602**	**$2,770,441**	**$6,201,544**	**$2,266,261**	**$15,669,172**

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

	2002	2001	2000
Cash from Operating Activities			
Net revenues (expenses)	$ 9,475	$ (337,401)	$ 240,977
Expenses (income) not requiring cash:			
Depreciation	254,332	247,247	242,673
Amortization of conservation and fish and wildlife	78,047	76,067	77,269
Amortization of nonfederal projects	229,180	176,258	323,619
Amortization of capitalization adjustment	(67,356)	(68,784)	(67,474)
AFUDC	(57,892)	(45,679)	(28,754)
(Increase) decrease in:			
Accounts receivable	88,765	(31,283)	(155,444)
Materials and supplies	115	(20,930)	6,785
Prepaid expenses	(98,547)	(101,254)	(3,200)
Increase (decrease) in:			
Accounts payable	(167,532)	138,687	100,699
Other	(6,399)	114,060	8,437
Cash provided by operating activities	262,188	146,988	745,587
Cash from Investment Activities			
Investment in:			
Utility plant	(487,030)	(399,220)	(310,165)
Conservation	(25,344)	141	—
Fish and wildlife	(6,102)	(16,493)	(13,898)
Cash used for investment activities	(518,476)	(415,572)	(324,063)
Cash from Borrowing and Appropriations			
Increase in federal constructions appropriations	168,583	230,388	129,953
Repayment of federal construction appropriations	(196,911)	(125,469)	(62,425)
Irrigation assistance	—	(16,560)	—
Increase in long-term debt	390,000	260,000	294,300
Repayment of long-term debt	(308,101)	(84,658)	(227,500)
Refinance of long-term debt	—	—	(68,800)
Payment of nonfederal debt	(229,180)	(176,258)	(323,619)
Cash (used for) provided by borrowing and appropriations	(175,609)	87,443	(258,091)
(Decrease) increase in cash	(431,897)	(181,141)	163,433
Beginning cash balance	667,306	848,447	685,014
Ending cash balance	**$ 235,409**	**$ 667,306**	**$ 848,447**

The accompanying notes are an integral part of these 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.

Standards of Ethical Conduct

As part of the United States federal government, employees of the FCRPS are bound by Standards of Ethical Conduct for Employees of the Executive Branch. The Standards contains 14 general principles that address topics such as placing ethical principles above private gain, not engaging in conflicts of interest, not using public office for private gain, and complying with all applicable governmental rules and regulations. The Standards document spells out these principles in great detail and includes examples of how to respond in situations where ethical dilemmas arise. All employees of the FCRPS, including executives, are required to receive federal ethics training and sign a document stating they understand the Standards of Ethical Conduct on an annual basis.

Reclassifications

Certain reclassifications were made to the 2000 and 2001 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2002. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's 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 established by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the 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. FERC and 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. By contract, 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 sets of conditions in which rate increases under the CRACs may trigger. 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 second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of accumulated net revenues is below a pre-determined 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. Of these certain rate adjustment clauses, some are calculated on forward-looking 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. The LB CRAC percentage changes every 6 months. The increase was 41 percent for the second half of fiscal 2002. The LB CRAC percentage will be revised for the six-month periods beginning Oct. 1, 2002 and April 1, 2003.

At Sept. 30, 2002, BPA has 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 ended Sept. 30, 2002. The August 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 requirement rates on top of the revised levels of the LB CRAC. SN CRAC did not trigger in fiscal 2002.

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 percent of BPA's power costs in exchange for a fixed percent of generation and capabilities. Settlement of any over or under collection is in the subsequent year. For the fiscal 2002 settlement, BPA has recognized a receivable of $49 million to be received in fiscal 2003.

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

BPA submitted a separate 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 October 11, 2001, FERC granted final approval for corrections of 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).

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) No. 71, Accounting for the Effects of Certain Types of Regulation.

SFAS 71 Assets

As of Sept. 30 — Thousands of dollars

	2002	2001
Nonfederal projects		
Conservation	$ 47,733	$ 50,189
Terminated nuclear facilities	3,829,269	3,804,312
Terminated hydro facilities	29,555	30,245
Trojan decommissioning cost	73,861	69,221
Conservation	409,571	444,021
Fish and wildlife	134,204	146,354
Additional retirement contributions	36,800	68,100
Total	**$ 4,560,993**	**$ 4,612,442**

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 $4.6 billion, shown in the table on page 31, reflect a decrease of $51 million from the prior year. Amortization of these costs aggregating $293 million in fiscal 2002, $259 million in 2001 and $276 million in fiscal 2000 is reflected in the Statements of Revenues and Expenses.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $93 million at Sept. 30, 2002, and $6 million at Sept. 30, 2001. Estimated unbilled revenues are included in accounts receivable in the accompanying Balance Sheets. 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.

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 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.

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 (2.5 percent to 6.5 percent in 2002, 2.5 percent to 6.6 percent in 2001 and 2.5 percent to 6.7 percent in 2000). Capitalization rates for other construction approximate the cost of borrowing from the U.S. Treasury (6.0 percent in 2002, 6.5 percent in 2001 and 6.6 percent in 2000).

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.

Fish Credits

The 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 Bonneville'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. Bonneville has taken this credit since 1995, in amounts that, with the exception of FY 2001, ranged between $26 million and $60 million.

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), BPA entered into residential exchange contracts with most of its electric utility customers. These contracts resulted 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 Oct. 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements determining exchange benefits for the period from July 1, 2001 through Sept. 30, 2011. These agreements provide for both sales of power and payments to the IOUs. The table below summarizes future IOU benefits as of Sept. 30, 2002.

Exchange Benefits

Thousands of dollars

IOU Benefits	
2003	$ 359,850
2004	359,850
2005	359,850
2006	359,850
Total	**$ 1,439,400**

Benefits beyond the current rate case period cannot currently be quantified.

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 approximately $55.2 million and $8.0 million to the U.S. Treasury during fiscal 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $36.8 million as of Sept. 30, 2002, which represents the additional deferred contribution for fiscal 1998, 1999, 2000, 2001 and 2002. 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, 2002, BPA has scheduled additional payments totaling $136.8 million as follows.

Scheduled Additional CSRS Contributions

Millions of dollars

Scheduled Contributions	
2003	$ 35.1
2004	30.9
2005	26.5
2006	23.2
2007	21.1
Total	**$ 136.8**

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

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 $484 million in 2002, $464 million in 2001 and $403 million in 2000.

Non-cash transactions include changes in nonfederal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $259 million in 2002, $61 million in 2001 and $40 million in 2000.

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 to mitigate the credit risk of financial instruments.

Bonneville has open purchase and sales contracts with a diverse group of customers including Enron Power Marketing Inc. (Enron). Enron and its parent company, Enron Corp. filed for bankruptcy protection in December 2001. Due to the nature of the contracts with Enron, management does not consider it necessary to record a provision for loss or for uncollectible amounts as of Sept. 30, 2002, relating to Enron transactions.

Credit Risk from California

California power markets have been in turmoil for several years, having experienced historically high power prices and volatility. 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) have resulted in concerns by energy suppliers that the Cal-ISO may not be a creditworthy supplier. 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.

Bonneville entered into certain power sales through the Cal-PX for which Bonneville has not yet been paid. In addition Bonneville sold power and related services to the Cal-ISO for which Bonneville has not yet been paid in full. Bonneville also has a long-term seasonal power exchange agreement with Southern California Edison. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, Bonneville has recorded provisions for uncollectible receivable and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

Deferred Credits

Deferred credits consist of $127 million paid to BPA from participants under the 3rd AC intertie capacity agreement, $126.4 million in advances from customers for projects which BPA is constructing on their behalf, $95.2 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $82.3 million current fair market value of purchased and written options and certain trading physical forward sales and purchases, $23.7 million leasing fees for fiber optic cable, $23.4 million in deferred CSRS, $21.1 million in unearned option premium revenue, and $.3 million in other miscellaneous long-term liabilities.

Deferred 3rd AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets. 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. 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. The current portion of deferred credits to be recorded as revenue in fiscal 2002 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. BPA had no material hedging or financial instruments outstanding as of Sept. 30, 2002.

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, 2002.

As of and for the years ended Sept. 30, 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

BPA sells put and call options for the purchase and sale of electricity at certain points in the future. BPA's intention is to fulfill all call options exercised with its estimated surplus generating capability at the future dates and to take delivery of power as a result of written put options if exercised. The megawatt-hour quantities that BPA sells and the premiums that BPA collects for the sales of these options are 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 fulfill these sales obligations with power purchases at a cost in excess of the prices stated in the contracts. In addition, BPA may be required to buy power at strike prices above market prices as a result of its written put option obligations.

As of Sept. 30, 2002, there were no written call options outstanding compared to 409,600 megawatt-hours outstanding with an average strike price of $130.25 per megawatt-hour as of Sept. 30, 2001. As of Sept. 30, 2002, written put options totaling 3,507,600 megawatt-hours were outstanding with an average strike price of $42.25 per megawatt-hour compared to 10,112,003 megawatt-hours outstanding as of Sept. 30, 2001. These options expire at various times through Dec. 2005. BPA records written options on a mark-to-market basis and includes 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, 2002 and 2001. 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.

Adoption of Statement 133

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. SFAS 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivatives be reported in net income or other comprehensive income, as appropriate.

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 paragraph 4 (a), and Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." 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. Bonneville may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2002, 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). While authoritative guidance in this area continued to emerge during fiscal year 2001, BPA management elected to apply the most current guidance available.

On June 29, 2001, the FASB issued definitive 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. 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 outside of the scope of SFAS 133 and therefore are not required to be marked to fair value in the financial statements. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

For the fiscal year ended Sept. 30, 2002 Statement of Revenues and Expenses BPA recorded $38.4 million of gains from SFAS 133 fair value application related to certain option and physical forward sales and purchase transactions. This included a $61.3 million gain for open option contracts and a $(22.9) million loss for certain physical forward sales and purchase transactions.

Recent Accounting Pronouncements

In June 2001, FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." Evaluations of SFAS 141 and 142 have been completed and we have determined there is no current effect on FCRPS financial statements.

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. BPA is continuing to determine the impact, if any, of SFAS 143 on BPA's financial statements. If applicable, SFAS 143 will be effective for BPA starting with the fiscal year ending Sept. 30, 2003.

In August 2001, FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. An evaluation of SFAS 144 has been completed and we have determined there is no current effect on FCRPS financial statements.

In April 2002, FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," and in June 2002, FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit of Disposal Activities." Evaluations of SFAS 145 and 146 have been completed and we have determined there is no current effect on FCRPS financial statements.

2. Long-Term Debt

To finance its capital programs, BPA is authorized by the Federal Columbia River Transmission System Act to issue to the U.S. Treasury up to $3.75 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 $3.75 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2002, $350 million of this reserved amount and $2,420 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, 2002, for similar maturities exceeds carrying value by approximately $497 million, or 18 percent. The table below reflects the terms and amounts of long-term debt.

U.S. Treasury Bonds

Long-Term Debt (a) — Thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Construction and Fish & Wildlife	Conservation	Cumulative Total
November 1999	none	2002	6.40%	$ 40,000		$ 40,000
January 1996	none	2003	5.90%	60,000		100,000
September 1999	none	2003	6.30%	20,000		120,000
April 2000 (b)	none	2003	6.85%	40,000		160,000
July 2000	none	2003	6.95%		$ 32,000	192,000
August 2000	none	2003	6.85%	15,300		207,300
January 1997	none	2004	6.80%	30,000		237,300
May 1999	none	2004	5.95%	26,200		263,500
September 1999 (b)	none	2004	6.40%	20,000		283,500
July 2000	none	2004	7.00%	50,000		333,500
June 2001 (b)	none	2004	4.75%	50,000		383,500
May 1997	none	2005	6.90%	80,000		463,500
January 2000	none	2005	7.15%	53,500		517,000
September 2000 (b)	none	2005	6.70%	20,000		537,000
January 2001	none	2005	5.65%	20,000		557,000
January 2001	none	2005	5.65%	25,000		582,000
March 2002	none	2005	4.60%	110,000		692,000
March 2002 (b)	none	2005	4.60%	30,000		722,000
June 2002	none	2005	3.75%	60,000		782,000
June 2002	none	2005	3.75%		40,000	822,000
August 1996	none	2006	7.05%	70,000		892,000
September 2000	none	2006	6.75%	40,000		932,000
September 2002	none	2006	3.05%	100,000		1,032,000
September 2002	none	2006	3.05%	30,000		1,062,000
September 2002 (b)	none	2006	3.05%	20,000		1,082,000
August 1997	none	2007	6.65%	111,300		1,193,300
April 1998	none	2008	6.00%	75,300		1,268,600
April 1998 (b)	none	2008	6.00%	25,000		1,293,600
August 1998	none	2008	5.75%	40,000		1,333,600
September 1998	none	2008	5.30%		104,300	1,437,900
July 1989	none	2009	8.55%		40,000	1,477,900
May 1998	none	2009	6.00%	72,700		1,550,600
May 1998	none	2009	6.00%		37,700	1,588,300
January 2001	none	2010	6.05%	30,000		1,618,300
January 2001	none	2010	6.05%	60,000		1,678,300
January 1996	2001	2011	6.70%		30,000	1,708,300
November 1996	2001	2011	6.95%	40,000		1,748,300
May 1998	none	2011	6.20%	40,000		1,788,300
June 2001	none	2011	5.95%	25,000		1,813,300
August 2001	none	2011	5.75%	50,000		1,863,300
January 1998	none	2013	6.10%	60,000		1,923,300
September 1998	none	2013	5.60%		52,800	1,976,100
January 1994	1999	2014	6.75%		13,265	1,989,365
February 1999	none	2014	5.90%	60,000		2,049,365
July 1995	2000	2025	7.70%	34,976		2,084,341
April 1998	2008	2028	6.65%	50,000		2,134,341
August 1998	none	2028	5.85%	106,500		2,240,841
August 1998	none	2028	5.85%	112,300		2,353,141
May 1998	2008	2032	6.70%	98,900		2,452,041
August 1993	1998	2033	6.95%	110,000		2,562,041
October 1993	1998	2033	6.85%	108,400		2,670,441
October 1993	1998	2033	6.85%	50,000		2,720,441
January 1994	1999	2034	7.05%	50,000		2,770,441
				$ 2,420,376	**$ 350,065**	**$ 2,770,441**
Less current portion						(207,300)
						$ 2,563,141

(a) The weighted average interest rate was 6 percent on outstanding long-term debt as of Sept. 30, 2002. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(b) Corps/Reclamation direct funding.

3. 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 Bonneville 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 $67.4 million for fiscal 2002 and $68.8 million for 2001, and $67.5 million for 2000. The weighted-average interest rate was 7.0 percent in 2002, and 6.9 percent in 2001 and 7.1 percent in 2000.

Construction and replacement of Corps and Reclamation generating facilities have historically been financed through annual federal appropriations. Annual appropriations were also 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 below shows the term repayments on the remaining federal appropriations as of Sept. 30, 2002.

Federal Appropriations

Thousands of dollars

Term Repayments	
2003	$ 46,687
2004	73,484
2005	110,989
2006	68,939
2007	33,694
2008+	4,308,809
Total	**$ 4,642,602**

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

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 has also 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 $175 million in fiscal 2002, $217 million in fiscal 2001 and $174 million in fiscal 2000 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $230 million, $473 million and $561 million for fiscal 2002, 2001 and 2000, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses.

The fair value of all Energy Northwest debt exceeds recorded value by $458 million or 7.6 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2002. All other nonfederal projects' debt approximates fair value as stated.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2002.

Nonfederal Projects

Thousands of dollars

	Debt Repayments
2003	$ 243,006
2004	280,350
2005	239,048
2006	267,387
2007	291,865
2008+	4,879,888
Total	**$ 6,201,544**

5. Commitments and Contingencies

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 $733 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 table below summarizes future irrigation assistance distributions as of Sept. 30, 2002.

Irrigation Assistance

Thousands of dollars

	Distributions
2003	$ —
2004	739
2005	—
2006	—
2007	—
2008+	732,195
Total	**$ 732,934**

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.

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 $6.2 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $12 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.2 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 $200 million, BPA could be subject to a retrospective assessment of $88.1 million limited to an annual maximum of $10 million.

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 and is expected to be recommended for management approval in November. 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 all site restoration 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 sum of expenditures for Columbia Generating Station is $340 million (1998 dollars). Payments to the sinking fund for the years ended Sept. 30, 2002, 2001 and 2000 were approximately $4 million per year. The sinking fund balance at Sept. 30, 2002, is $71 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, 2002, BPA's 30-percent share of this estimated remaining liability is $74 million which has been recorded net of the decommissioning trust fund balance of $6 million in the accompanying Balance Sheet. 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 2000, 2001 and 2002. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund is being applied directly to the decommissioning expenses. In 2002, the decommissioning trust fund was used to fund a portion of the 2002 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.

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.

Endangered Species Act

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

Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2007.

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, 2002.

Purchase Power and Sales Commitments

Thousands of dollars

	Purchase	Sales
2003	$ 1,046,243	$ 2,122,146
2004	963,168	2,104,685
2005	996,904	2,104,686
2006	939,352	2,111,821
2007	98,823	100,445
2008+	362,570	275,043
Total	**$ 4,407,060**	**$ 8,818,826**

Augmentation commitments run through the rate case which ends in 2006.

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. Intersegment 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 $994 million for fiscal 2002 ($3,534 million Operating Revenues less $38 million SFAS 133 mark-to-market, $38 million U.S. Treasury Credits for Fish, $1,177 million Operations and Maintenance and $1,287 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

Major Customers

During fiscal 2002, 2001 and 2000, 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
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
2000				
Unaffiliated Revenues	$ 2,701,373	$ 365,613	$ —	$ 3,066,986
Intersegment Revenues	46,385	212,727	(259,112)	—
Operating Revenues	$ 2,747,758	$ 578,340	$ (259,112)	$ 3,066,986
Net Operating Margin	$ 1,307,980	$ 308,188	$ (123,224)	$ 1,492,944

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2002 — 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	$ 5,482,014	$ 5,097,741	$ 384,273	$ 5,482,014	$ —	$ —	$ —
Bureau of Reclamation							
Boise	118,268	16,576	1,263	17,839	639	65,671	66,310
Columbia Basin	1,903,883	1,215,976	27,777	1,243,753	493,430	143,154	636,584
Green Springs	35,500	11,161	—	11,161	9,934	8,070	18,004
Hungry Horse	148,423	120,731	817	121,548	—	—	—
Minidoka-Palisades	381,854	110,381	54	110,435	386	72,505	72,891
Yakima	227,818	6,160	13	6,173	13,025	127,511	140,536
Total Bureau Projects	2,815,746	1,480,985	29,924	1,510,909	517,414	416,911	934,325
Corps of Engineers							
Albeni Falls	48,141	40,420	3,106	43,526	—	—	—
Bonneville	1,371,207	873,380	93,574	966,954	—	—	—
Chief Joseph	618,659	565,479	13,006	578,485	—	163	163
Cougar	93,683	20,311	31,178	51,489	—	3,288	3,288
Detroit-Big Cliff	69,365	40,998	2,241	43,239	—	5,050	5,050
Dworshak	376,065	314,733	5,172	319,905	—	—	—
Green Peter-Foster	93,617	49,722	3,635	53,357	—	6,210	6,210
Hills Creek	50,242	17,665	892	18,557	—	4,616	4,616
Ice Harbor	212,364	149,316	3,910	153,226	—	—	—
John Day	645,959	477,534	21,094	498,628	—	—	—
Libby	574,639	430,031	2,636	432,667	—	—	—
Little Goose	250,475	207,582	1,431	209,013	—	—	—
Lookout Point-Dexter	107,949	49,603	6,369	55,972	—	1,489	1,489
Lost Creek	149,751	26,978	10	26,988	—	2,186	2,186
Lower Granite	405,213	329,697	2,007	331,704	—	—	—
Lower Monumental	268,538	224,511	1,376	225,887	—	—	—
McNary	366,624	284,030	8,818	292,848	—	—	—
The Dalles	404,420	303,324	51,805	355,129	—	—	—
Lower Snake	260,079	256,065	1,445	257,510	—	—	—
Columbia River Fish Bypass	800,264	247,942	515,454	763,396	—	—	—
Total Corps Projects	7,167,254	4,909,321	769,159	5,678,480	—	23,002	23,002
AFUDC on Direct Funded Projects	16,822	—	16,822	16,822	—	—	—
Irrigation Assistance at 12 Projects							
having no power generation	201,179	—	—	—	157,144	44,035	201,179
Total Plant Investment	15,683,015	11,488,047	1,200,178	12,688,225	674,558	483,948	1,158,506
Repayment Obligation Retained							
by Columbia Basin Project	4,639	2,836 (a)	—	2,836 (a)	1,803	—	1,803
Investment in Teton Project (b)	79,107	—	7,269	7,269	56,573	3,681	60,254
Total	**$15,766,761**	**$11,490,883**	**$1,207,447**	**$12,698,330**	**$732,934**	**$487,629**	**$1,220,563**

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

(b) 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	—	—	—	—	34,119	15.62%
Columbia Basin	—	16,590	6,073	172	711	91.24%
Green Springs	—	—	—	—	6,335	59.42%
Hungry Horse	—	26,875	—	—	—	81.89%
Minidoka-Palisades	—	64,404	2,570	10,471	121,083	29.02%
Yakima	—	2,432	50,365	284	28,028	8.43%
Total Bureau Projects	**—**	110,301	59,008	10,927	190,276	72.04%
Corps of Engineers						
Albeni Falls	180	269	—	4,166	—	90.41%
Bonneville	400,925	—	—	1,266	2,062	70.52%
Chief Joseph	—	—	4,977	6,034	29,000	93.51%
Cougar	548	38,358	—	—	—	54.96%
Detroit-Big Cliff	219	20,857	—	—	—	62.34%
Dworshak	9,618	31,463	—	15,079	—	85.07%
Green Peter-Foster	365	30,322	—	1,693	1,670	56.99%
Hills Creek	630	26,439	—	—	—	36.94%
Ice Harbor	55,623	—	—	3,515	—	72.15%
John Day	90,943	18,025	—	11,954	26,409	77.19%
Libby	—	95,141	876	15,318	30,637	75.29%
Little Goose	34,739	—	—	4,119	2,604	83.45%
Lookout Point-Dexter	745	49,141	—	602	—	51.85%
Lost Creek	—	53,022	24,507	29,418	13,630	18.02%
Lower Granite	52,593	—	—	13,074	7,842	81.86%
Lower Monumental	39,370	—	—	2,864	417	84.12%
McNary	68,856	—	—	4,920	—	79.88%
The Dalles	47,191	—	—	2,078	22	87.81%
Lower Snake	2,569	—	—	—	—	99.01%
Columbia River Fish Bypass	34,230	2,638	—	—	—	95.39%
Total Corps Projects	839,344	365,675	30,360	116,100	114,293	79.23%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.11%
Total Plant Investment	839,344	475,976	89,368	127,027	304,569	85.21%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project (b)	—	9,151	—	2,433	—	80.70%
Total	**$839,344**	**$485,127**	**$89,368**	**$129,460**	**$304,569**	**85.2219%**

QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2003

Federal Columbia River Power System

Comparative Balance Sheets (Unaudited)
(Thousands of Dollars)

	March 31 2003	March 31 2002
Assets		
Utility Plant		
Completed plant	**$11,576,469**	$11,323,659
Accumulated depreciation	**(4,174,785)**	(3,940,073)
	7,401,684	7,383,586
Construction work in progress	**1,290,326**	996,716
Net utility plant	**8,692,010**	8,380,302
Nonfederal Projects	**6,204,572**	6,176,059
Trojan Decommissioning Cost	**73,726**	66,710
Conservation, net of accumulated amortization	**391,701**	413,710
Fish & Wildlife, net of accumulated amortization	**126,475**	141,426
Current Assets	**1,092,407**	1,307,215
Other Assets	**143,375**	201,819
	$16,724,266	$16,687,241
Capitalization and Liabilities		
Accumulated Net Expenses	**($1,906)**	($284,626)
Federal Appropriations	**4,596,506**	4,671,085
Capitalization Adjustment	**2,158,548**	2,226,078
Long-Term Debt	**2,663,141**	2,622,542
Nonfederal Projects Debt	**5,961,206**	5,958,230
Trojan Decommissioning Reserve	**63,726**	54,710
Current Liabilities	**801,497**	869,715
Deferred Credits	**481,548**	569,507
	$16,724,266	$16,687,241

The irrigation assistance distribution of $16,560 for fiscal 2001 is included in accumulated net expenses.

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

	Six months ended March 31		Twelve months ended March 31	
	2003	2002	**2003**	2002
Operating Revenues:				
Revenues	**$1,712,807**	$1,726,629	**$3,393,582**	$3,304,467
SFAS 133 mark-to-market (loss) gain	**21,230**	1,319	**58,265**	(3,119)
Other revenues	**20,789**	17,191	**53,169**	50,347
U.S. Treasury credits for fish	**66,264**	26,158	**78,506**	534,649
Operating Revenues	**1,821,090**	1,771,297	**3,583,522**	3,886,344
Operating Expenses:				
Operations and maintenance	**567,490**	577,068	**1,310,129**	1,150,221
Purchased power	**584,260**	738,704	**1,132,423**	1,896,945
Non-Federal projects	**112,993**	170,762	**172,406**	325,623
Federal projects depreciation	**173,721**	160,923	**348,003**	324,769
Operating Expenses	**1,438,464**	1,647,457	**2,962,961**	3,697,558
Net operating revenues (expenses)	**382,626**	123,840	**620,561**	188,786
Interest Expense	**172,856**	187,315	**337,841**	354,924
Net (Expenses) Revenues	**$209,770**	($63,475)	**$282,720**	($166,138)

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.

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APPENDIX B

SUMMARY OF THE BOND ORDINANCE

The following summary is an outline of certain provisions of the Bond Ordinance, is not to be considered a full statement hereof and is qualified by reference to the complete Bond Ordinance. For purposes of this Appendix, Bonds includes the 2003 Bonds and Future Parity Bonds.

Certain Definitions Used in the Bond Ordinance

"Administrative Costs" has the same meaning as in the Project Agreement. See APPENDIX E.

"Annual Project Costs" has the same meaning as in the Project Agreement. See APPENDIX E.

"Code" means the Internal Revenue Code of 1986, as the same may be amended from time to time, and the regulations promulgated thereunder.

"Conservation" means any reduction in electric energy consumption resulting from an increase in the efficiency of electric energy use, production or distribution.

"Conservation Project" or "Project" means the conservation measures and units to be installed pursuant to the Project Agreement designed to increase efficiency in electric use, production or distribution or the direct application of a renewable resource that is expected to result in load reduction, which project is undertaken on behalf of customers served by the City, but shall not include the Electric System or any other activities, properties, or rights or assets, real or personal, tangible or intangible, that hereafter may be purchased, constructed or otherwise acquired by the City as a system that is not undertaken pursuant to the Project Agreement and is declared by the Council at the time of financing thereof to be separate from the Conservation Project, the revenues of which may be pledged to the payment of bonds issued to purchase, construct or otherwise acquire or expand such separate system or otherwise may be pledged to the payment of the bonds of another such separate system of the City.

"Conservation Revenues" or "Revenues" means all income, revenues, receipts and payments derived by the City in connection with the Conservation Project, including payments received or receivable pursuant to the Project Agreement, except Trustee Costs paid by Bonneville under the Project Agreement, reward payments as described in the Project Agreement and any loan repayments returned to the City if such repayments are hereafter authorized by the Project Agreement, together with the proceeds received by the Trustee on behalf of the City from any Derivative Product, and with the investment income earned on money held in any fund or account established under the Bond Ordinance and held by the Trustee or the City, including any bond redemption fund and the accounts therein, in connection with the Conservation Project, exclusive of investments irrevocably pledged to the defeasance of any specific Conservation Bonds, such as Bonds heretofore or hereafter refunded, or any Bonds defeased pursuant to the Bond Ordinance or other Bonds defeased, or the payment of which is provided for, under any similar provision of any other bond ordinance of the City, and exclusive of money in any fund or account hereafter created for the purpose of complying with the rebate provisions of Section 148 of the Code.

"Conservation Revenues" shall not include any income derived by the City through any other activities, properties, rights or assets that may hereafter be purchased, constructed or otherwise acquired by the City as a separate system and which are not part of the Conservation Project.

"Debt Service" means the sum of the amounts required to be paid when due for the following: (a) the interest due on all outstanding Bonds, excluding interest to be paid from the proceeds of the sale of Bonds; (b) the principal of all outstanding Bonds and the Sinking Fund Requirement for Term Bonds, if any; (c) amounts required to pay premiums for redeeming Bonds prior to their scheduled maturity; and (d) any regularly scheduled City Payments, adjusted by any regularly scheduled Reciprocal Payments, to the extent not covered in (a), (b) or (c) above. For purposes of this definition, the principal and interest portions of capital appreciation Bonds and deferred income Bonds becoming due at maturity or by virtue of a sinking fund installment shall be included in the calculations of accrued interest or principal and any variable rate Bonds shall be calculated in such manner as is specified in the Supplemental Ordinance.

"Derivative Product" means a written contract or agreement between the City and a third party that has (or whose obligations are unconditionally guaranteed by a party that has) as of the date of the Derivative Product at least an investment grade rating from a rating agency (the "Reciprocal Payor"), which provides that the City's obligations thereunder will be conditioned on the performance by the Reciprocal Payor of its obligations under the agreement:

(1) under which the City is obligated to pay, on one or more scheduled and specified Derivative Payment Dates, the City Payments in exchange for the Reciprocal Payor's obligation to pay or to cause to be paid to the City, on scheduled and specified Derivative Payment Dates, the Reciprocal Payments;

(2) for which the City's obligations to make the City Payments may be secured by a pledge of and lien on Conservation Revenues on an equal and ratable basis with the outstanding Bonds;

(3) under which Reciprocal Payments are to be made directly into the Bond Fund;

(4) for which City Payments are either specified to be one or more fixed amounts or are determined as provided by the Derivative Product; and

(5) for which the Reciprocal Payments are either specified to be one or more fixed amounts or are determined as set forth in the Derivative Product.

"Electric System" means the electric utility properties, rights, and assets, real and personal, tangible and intangible, now owned and operated by the City and used or useful in the generation, transmission, distribution and sale of electric energy and the business incidental thereto, and all properties, rights and assets, real and personal, tangible and intangible, hereafter constructed or acquired by the City as additions, betterments, improvements or extensions to said electric utility properties, rights and assets.

"Fiscal Year" means the Fiscal Year used by the City at any time. Currently, the Fiscal Year is the 12-month period beginning January 1 of each year

"Outstanding" means Bonds the principal of and interest on which has not been paid under the Bond Ordinance and which have not been defeased pursuant to the Bond Ordinance.

"Permitted Investments" means any investments or investment agreements which the City is permitted to make under the laws of the State of Washington, as amended from time to time and that are consistent with Internal City investment policies.

"Serial Bonds" means Bonds failing due by their terms in specified years for which no mandatory sinking fund payments are required.

"Sinking Fund Requirement" means, for any Fiscal Year, the principal amount of Term Bonds required to be purchased, redeemed or paid at maturity or paid into any sinking fund account for such Fiscal Year as established by the Supplemental Ordinance authorizing the issuance of such Term Bonds.

"Term Bonds" means Bonds of any principal maturity that are subject to mandatory redemption or for which mandatory sinking fund payments are required.

Funds and Accounts

1. Conservation Project Revenue Fund. The City has pledged to pay all Conservation Revenues into the Conservation Project Revenue Fund except as specifically provided in the Bond Ordinance. The Conservation Revenues in the Conservation Project Revenue Fund and the Bond Fund shall be applied as specified under "SECURITY FOR THE 2003 BONDS — Flow of Funds" in this Official Statement.

2. Bond Fund. Bonneville has agreed in the Project Agreement to make payments directly to the Trustee for deposit as follows:

(a) Into the Interest Account, on or prior to each interest payment date, the amount equal to the installment of interest next falling due on all Bonds.

(b) Into the Serial Bond Principal Account, on or prior to each date upon which an installment of principal on Serial Bonds falls due, the amount equal to the installment of principal next falling due on the Serial Bonds.

(c) Into the Term Bond Principal Account, on or prior to each date on which a Sinking Fund Requirement falls due, the amount equal to the Sinking Fund Requirements next falling due on all Term Bonds.

Money in the Bond Fund shall be invested in Permitted Investments.

Additional Bonds

1. Bonds. Additional Bonds may be issued to pay all or a portion of the costs of the Conservation Project or to refund the Bonds or additional Bonds if (a) there is no deficiency in the Bond Fund and no Event of Default has occurred and is continuing, (b) Bonneville has approved the issuance of such additional Bonds, (c) Debt Service on the additional Bonds is payable under the Project Agreement, and (d) there is an opinion of bond counsel that the additional Bonds are enforceable and binding obligations of the City.

2. Junior Lien Bonds. The City may issue bonds or other obligations of indebtedness relating to the Conservation Project payable from Conservation Revenues subordinate to the payments required to be made from the Revenue Fund into the Bond Fund for the Bonds.

3. Other System Bonds. The City may issue bonds payable from Electric System revenues or revenues of any other separate system.

4. Derivative Products. The City may enter into Derivative Products on a parity with the Bonds if the City meets the requirements for additional Bonds described under Section 1 above.

Defeasance of Bonds

The City, with Bonneville's approval, may refund or defease all or a portion of the then outstanding Bonds by setting aside in a special fund money or non-callable Government Obligations sufficient, together with earnings thereon, to accomplish the refunding or defeasance. In that case all rights of the owners of the defeased or refunded Bonds in the benefit or security of the Bond Ordinance will cease, except that such owners will have the right to receive payment of the principal of, premium, if any, and interest on their Bonds.

Covenants

In the Bond Ordinance the City has agreed to various covenants, including the following:

1. Books of Account. The City shall keep proper books of account, which will be audited annually by the Washington State Auditor's office or an independent public accountant. Any bondowner may obtain at the office of the City or upon written request to the City copies of the City's audited financial statements coveting the Conservation Project.

2. Tax Covenants. The City will not take any action that will cause the Bonds to be "arbitrage bonds" or "private activity bonds" under the Code.

3. Protection of Security. Nothing in the Project Agreement will be amended, modified or otherwise altered in any manner that will reduce the payments pledged as security for the Bonds, or extend the time of such payments provided in the Project Agreement or in any manner materially adversely affect the rights of the Owners of the Bonds.

Trustee

U.S. Bank, National Association, Portland, Oregon, is appointed to act as Trustee for the owners of all Bonds. The Trustee may resign upon 45 days' notice mailed to each bondowner or published in a newspaper of general circulation or financial journal published in New York. Such resignation shall take effect upon the appointment of a new Trustee. The Trustee may be discharged by the City as long as an Event of Default has not occurred and is continuing or by the owners of a majority of the outstanding Bonds. The consent of Bonneville shall be required for any such discharge. If the Trustee resigns or is discharged the City shall appoint a new Trustee. At any time within one year after such appointment, the Owners of a majority of the outstanding Bonds may appoint a successor Trustee, which shall supersede any Trustee appointed by the City.

Prior to the occurrence of an Event of Default and subsequent to the curing of such Event of Default, the Trustee shall not be liable except for the performance of its duties and obligations set forth in the Bond Ordinance and to act in good faith in the performance thereof, and no implied duties or obligations shall be incurred by the Trustee other than those specified in the Bond Ordinance. If an Event of Default has occurred and not been cured, the Trustee shall use the same degree of care and skill in the exercise of its duties set forth in the Bond Ordinance as a prudent person would exercise or use under the circumstances in the conduct of his or her own affairs. The Trustee shall not be deemed to have knowledge of any Event of Default not known to the Trustee.

The Trustee is not responsible for the recitals of fact in the Bond Ordinance and makes no representations as to the legal validity or sufficiency of the Bond Ordinance or of any Bonds or in respect of the security afforded by the Bond Ordinance.

Any money deposited with the Paying Agent and not applied to the payment of Bonds within three years following the final maturity or redemption of the Bonds shall be transferred to the City free from the trusts created by the Bond Ordinance.

Other than with respect to making the payments of principal of and interest on the Bonds when due from money held by the Trustee under the Bond Ordinance, and with respect to the redemption of the Bonds, the Trustee shall be under no obligation to institute any suit or proceeding, to enter any appearance or in any way defend in any suit in which it may be defendant (except for arising from the Trustee's negligence or willful misconduct or other breach of fiduciary duty), or to take any steps in the execution of the trusts created or in the enforcement of any rights and powers under the Bond Ordinance, until it shall be reasonably assured that repayment of all costs and expenses, outlays and counsel fees and other reasonable disbursements in connection therewith will occur in a timely manner. However, the Trustee may begin suit, or appear in and defend suit, or do anything else in its judgment proper to be done by it as such Trustee, without assurance of reimbursement or indemnity, and in such case the Trustee shall be reimbursed by the owners of Bonds for all costs and expenses, liabilities, outlays and counsel fees and other reasonable disbursements properly incurred in connection therewith, unless such liability or disbursement is adjudicated to have resulted from the negligence or willful misconduct of the Trustee or other breach of fiduciary duty. If the Owners of Bonds shall fail to make such reimbursement or indemnification, the Trustee may reimburse itself from any money in its possession under the provisions of the Bond Ordinance subject only to the prior lien of the Bonds for the payment of the principal thereof and interest thereon.

Events of Default and Remedies

1. Events of Default. The following constitute "Events of Default" under the Bond Ordinance:

(a) Default in the punctual payment of the principal of any Bond when the same shall become due either at maturity or by mandatory redemption;

(b) Default in the punctual payment of interest on any Bond when the same shall become due, or

(c) Default in the observance of any other of the covenants and conditions in the Bond Ordinance and such default continues for 90 days after the City receives from the Trustee or from the owners of not less than 20% in principal amount of any series of Bonds outstanding a written notice specifying and demanding the cure of such default.

2. Remedies. The Trustee may, if an Event of Default is not remedied, take such steps and institute such proceedings as it deems appropriate to collect all sums owing and to protect the rights of bondowners. If an Event of Default exists, there is no right to accelerate payment of all or any of the interest on or principal of the Bonds not then due and payable. The owners of the Bonds shall be deemed to irrevocably appoint the Trustee as the lawful trustee of the bondowners. The owners of at least 50% in principal amount of the Outstanding Bonds may, in certain circumstances, direct the time, method and place of conducting any proceedings for any remedy available to the Trustee. No bondowner may institute any proceeding for the enforcement of the Bond Ordinance unless an Event of Default is continuing and the owners of not less than 50% in principal amount of the outstanding Bonds have given the City and the Trustee written notice to institute such proceeding and the Trustee has refused or neglected to comply within a reasonable time; provided that nothing in the Bond Ordinance shall impair the rights of action, which are absolute, of any Owner to enforce the payment of his or her Bonds, or to reduce to judgment his or her claim against the City for the payment on his or her Bonds, without reference to, or the consent of, the Trustee or any bondowner.

Supplemental Ordinances

1. Supplemental Ordinances Without Consent of Bondowners. The Council may, with the consent of Bonneville, adopt a Supplemental Ordinance authorizing the issuance of additional Bonds or an ordinance amending or supplementing the Bond Ordinance to provide for the issuance of additional Bonds or to make any other change which does not materially and adversely affect the interest of the bondowners.

2. Supplemental Ordinances With Consent of Bondowners. With the consent of Bonneville and the Owners of not less than 66% in principal amount of the outstanding Bonds, the City may adopt an Ordinance amending or supplementing the Bond Ordinance; provided, that, without the specific consent of the Owner of each Bond that would be affected, no such Supplemental Ordinance shall: (a) change the fixed maturity date for the payment of the principal of any Bond or the date for the payment of interest or the terms of the redemption thereof, or reduce the principal amount of any Bond or the rate of interest thereon or the redemption price (or the redemption premium) payable upon the redemption or prepayment thereof; (b) reduce the percentage of Bonds the owners of which are required to consent to any Supplemental Ordinance; (c) give to any Bond any preference over any other Bond; or (d) create any pledge of the Conservation Revenues superior or equal to the pledge of and lien and charge for the payment of the Bonds.

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APPENDIX C

PROPOSED FORM OF LEGAL OPINION

City of Tacoma
Tacoma, Washington

Seattle-Northwest Securities Corporation
Seattle, Washington

Goldman, Sachs & Co.
Seattle, Washington

Re: City of Tacoma, Conservation System Project Revenue Refunding Bonds, 2003

Ladies and Gentlemen:

We have acted as bond counsel to the City of Tacoma, Washington (the "City") and examined a certified transcript of all of the proceedings taken in the matter of the issuance by the City of its Conservation System Project Revenue Refunding Bonds, 2003 in the aggregate principal amount of $17,065,000 (the "2003 Bonds"), issued to provide funds to refund the Conservation System Project Revenue Bonds, 1994, issued in the principal amount of $22,185,000 (the "1994 Bonds") for the purpose of financing the Conservation Project by the City, and to pay the cost of issuance of the 2003 Bonds.

The 2003 Bonds will be issued pursuant to (1) Substitute Ordinance No. 25623 approved November 8, 1994 and Substitute Resolution No. 32847 approved on December 13, 1994 (together, the "Bond Ordinance") authorizing the Conservation System Revenue Bonds of the City to be issued in series; and (2) Second Supplemental Ordinance No. 27074 approved April 1, 2003 and Substitute Resolution No. 35850 approved May 13, 2003 (together, the "Second Supplemental Ordinance") authorizing the issuance of the 2003 Bonds for purposes of refunding the 1994 Bonds.

The 2003 Bonds are not subject to prior redemption.

As to questions of fact material to our opinion, we have relied upon the certified proceedings and other certifications of public officials furnished to us without undertaking to verify the same by independent investigation.

From such examination it is our opinion, as of this date and under existing law, that:

1. The City has the right and power under its charter and the laws of the State of Washington to adopt the Second Supplemental Ordinance, and the Second Supplemental Ordinance has been duly and lawfully adopted by the City, is in full force and effect, is valid and binding upon the City and is enforceable in accordance with its terms.

2. The Second Supplemental Ordinance creates valid pledges of (i) Conservation Revenues, which include all income, revenue and payments derived by the City in connection with the Conservation Project, including payments received or receivable pursuant to the Project Agreement, except any reward payments as described in the Project Agreement, Trustee Costs, and any loan repayments returned to the City if permitted by the Project Agreement, (ii) the proceeds of the sale of the 2003 Bonds and any bonds hereafter issued on a parity with the Bonds ("Future Parity Bonds") to the extent held in funds established under the Bond Ordinance, and

(iii) money and assets, if any, credited to the Conservation Project Revenue Fund, the Bond Fund, the Implementation Fund, the Refunding Account or any junior lien fund except proceeds from junior lien obligations, exclusive of money to be rebated to the federal government. Such pledges constitute a lien and charge equal in rank to the lien on such proceeds, revenues, money and securities required to pay and secure obligations issued on a parity with the 2003 Bonds and superior to all other charges of any kind or nature, and the provisions of the Second Supplemental Ordinance.

3. The City is duly authorized and entitled to issue the 2003 Bonds, and the 2003 Bonds have been duly and validly authorized and issued by the City in accordance with the laws of the State of Washington. The 2003 Bonds constitute valid and binding obligations of the City as provided in the Second Supplemental Ordinance, are enforceable in accordance with their terms and the terms of the Second Supplemental Ordinance and are entitled to the benefits of the Second Supplemental Ordinance. The 2003 Bonds are not general obligations of the City and are payable solely from the sources specified in the Second Supplemental Ordinance. Neither the State of Washington nor any political subdivision thereof, other than the City, is obligated to pay the principal of, premium, if any, or interest on the 2003 Bonds.

4. Interest on the 2003 Bonds is excluded from gross income for purposes of federal income taxation pursuant to Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). The 2003 Bonds are not private activity bonds. Interest on the 2003 Bonds is not an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals or corporations, but is taken into account in the computation of adjusted current earnings for purposes of the corporate alternative minimum tax under Section 55 of the Code. The opinions stated in this paragraph are subject to the condition that the City comply with all requirements of the Code that must be satisfied subsequent to the issuance of the 2003 Bonds in order that interest thereon be, or continue to be, excluded from gross income for federal income tax purposes. The City has covenanted to comply with all such requirements. Failure to comply with certain of such requirements may cause interest on the 2003 Bonds to be included in gross income for federal income tax purposes retroactive to the date of issuance of the 2003 Bonds.

Except as stated herein, we express no opinion regarding any federal, state or local tax consequences arising with respect to ownership of the 2003 Bonds.

The opinions contained in paragraphs 1, 2 and 3 above are qualified to the extent that the enforcement of the rights and remedies of such owners of the 2003 Bonds may be limited by laws relating to bankruptcy, reorganization, insolvency, moratorium or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and the exercise of judicial discretion.

Very truly yours,

PRESTON GATES & ELLIS LLP

By
Nancy M. Neraas

APPENDIX D

BOOK-ENTRY SYSTEM

The following information has been provided by The Depository Trust Company, New York, New York ("DTC"). The City makes no representation regarding the accuracy or completeness thereof. Each actual purchaser of a 2003 Bond (a "Beneficial Owner") should therefore confirm the following with DTC or the Participants (as hereinafter defined).

DTC will act as securities depository for the 2003 Bonds. The 2003 Bonds will be issued as fully-registered 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 bond certificate will be issued for each maturity of the 2003 Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 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, Inc., 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, and trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the 2003 Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the 2003 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2003 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 Owners entered into the transaction. Transfers of ownership interests in the 2003 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 2003 Bonds, except in the event that use of the book-entry system for the 2003 Bonds is discontinued.

To facilitate subsequent transfers, all 2003 Bonds deposited by 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 2003 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 2003 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2003 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

When notices are given, they shall be sent by the Bond Registrar to DTC only. Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the 2003 Bonds within a series 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 2003 Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the City 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 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the 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 City or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC (nor its nominee), the Bond Registrar, or the City, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of the City or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2003 Bonds at any time by giving reasonable notice to the City and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, 2003 Bond certificates are required to be printed and delivered.

The City may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, 2003 Bond certificates will be printed and delivered.

With respect to 2003 Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, the City and the Bond Registrar shall have no responsibility or obligation to any Participant or to any person on behalf of whom a Participant holds an interest in the 2003 Bonds with respect to (i) the accuracy of the records of DTC, Cede & Co. or any Participant with respect to any ownership interest in the 2003 Bonds; (ii) the delivery to any Participant or any other person, other than a bond owner as shown on the Bond Register, of any notice with respect to the 2003 Bonds, including any notice of redemption; (iii) the payment to any Participant or any other person, other than a bond owner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the 2003 Bonds; (iv) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the 2003 Bonds; (v) any consent given or action taken by DTC as registered owner; or (vi) any other matter. The City and the Bond Registrar may treat and consider Cede & Co., in whose name each 2003 Bond is registered on the Bond Register, as the holder and absolute owner of such 2003 Bond for the purpose of payment of principal and interest with respect to such 2003 Bond, for the purpose of giving notices of redemption and other matters with respect to such 2003 Bond, for the purpose of registering transfers with respect to such 2003 Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the Participant acquires an interest in the 2003 Bonds.

APPENDIX E

SUMMARY OF THE
PROJECT AGREEMENT

A summary of certain provisions of the Project Agreement between the City and Bonneville (each a "Party" and together the "Parties") relating to the Conservation Project (the "Project Agreement") is set forth below. The summary is not to be considered a full statement of the Project Agreement and is qualified by reference to the complete text of the Project Agreement. For the purpose of this Appendix, "Bonds" includes the 2003 Bonds and Future Parity Bonds.

Term

The Agreement is effective from February 23, 1994 until the later of the time (a) no funds remain in the Implementation Fund or (b) there are no Bonds Outstanding.

Certain Definitions Used in the Agreement

"Actual Implementation Costs" means the sum of (1) Implementation Costs which have been or will be invoiced to Bonneville or the Trustee; (2) Obligated Costs; and (3) Partial Payments.

"Administrative Costs" means all customary and reasonable direct, indirect, general and administrative, and overhead costs as defined in certain United States Office of Management and Budget circulars. Administrative Costs shall not include Evaluation Costs, any discrete costs incurred by Tacoma for the management of Tacoma funds loaned to Consumers, or the costs of insurance premiums relating to the liability coverage required by section 6(d) of the Project Agreement.

"Annual Project Costs" means all of the costs incurred during any Fiscal Year resulting from the implementation of the Project, other than Actual Implementation Costs, Debt Service, and Trustee Costs, including but not limited to such costs which are properly chargeable to the Project as the Parties may from time to time agree.

"Bond Financing Costs" means the costs and expenses necessary and appropriate for the authorization, issuance and sale of Bonds pursuant to the Bond Ordinance. Such costs include, but are not limited to, bond discounts, bond insurance premiums, letter of credit fees, the cost of compliance with disclosure or other similar requirements, and fees for bond counsel and other legal counsel, independent auditors, bond and other printing, financial advisor, bond registrar and Trustee Costs.

"Conservation" means any reduction in electric energy consumption resulting from an increase in the efficiency of electric energy use, production or distribution.

"Debt Service" means the amounts required to pay, when due, the following:

(1) the interest due on all Bonds, excluding interest paid from Bond Proceeds; and

(2) the principal of all Bonds, whether at scheduled maturity or by reason of redemption, including sinking fund installments required to amortize Bonds, including term bonds, if any; and

(3) amounts required to pay premiums for redeeming Bonds prior to their scheduled maturity; and

(4) any regularly scheduled payments required to be made by the City pursuant to a derivative product adjusted by any regularly scheduled payments to be made by another party to the derivative product, to the extent not covered in sections (1), (2) and (3) above.

For purposes of this definition, the principal and interest portions of capital appreciation Bonds and deferred income Bonds becoming due at maturity or by virtue of a sinking fund installment shall be included in the calculations of accrued interest or principal and any variable rate Bonds shall be calculated in such manner as specified in the Bond Ordinance.

“Energy Savings Achieved” means the ascribed, estimated, evaluated, or verified energy savings in kilowatt-hours (kWh) attributable to Completed Units.

“Fiscal Year” means any consecutive 12 month period commencing October 1 and ending on the following September 30.

“Implementation Costs” means the actual costs to install or implement Measures, actual Administrative Costs, and the Evaluation Costs incurred by the City for Completed Units. Implementation Costs are either payable from the Implementation Fund, or during the period in which funding is provided directly from Bonneville, from the Implementation Budget.

“Implementation Period” means the period for which Bonneville has provided an approved Implementation Budget. The initial Implementation Period begins on the Effective Date and ends at 2400 hours on September 30, 1995.

“Measure” means materials or equipment installed, or activities implemented, to achieve Conservation, as set forth in Exhibit C of the Project Agreement.

“Obligated Unit” means a Unit for which the City and a Consumer have executed an implementation or installation contract, and the City has obligated funding for implementation or installation, during an Implementation Period, and is not a Completed Unit upon termination of that Implementation Period.

“Project” means all Completed Units delivered during the Project Implementation.

“Project Implementation Period” means the period of time from the Effective Date through September 30, 2001, unless shortened pursuant to the Project Agreement, during which Completed Units have been or are being delivered. The Project Implementation Period may be extended, if agreed, if funds remain in the Implementation Fund.

“Trustee Costs” means the fees, costs and expenses incurred by the Trustee and any paying agent and registrar in discharging their respective obligations under the Bond Ordinance.

“Uncontrollable Force” means an act or event beyond the reasonable control of a Party, which by exercise of due diligence and foresight such Party could not reasonably have been expected to avoid or remove, which impairs the ability of the Party to perform, and includes, but is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, accident, fire, lightning and other natural catastrophes; epidemic, war, labor or material shortage, strike or labor dispute, or sabotage; and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities against any action taken or not taken by a Party, after a good faith effort by the appropriate Party to obtain (1) relief from such other; or (2) any necessary authorizations or approvals from any governmental agency or regulatory authority.

“Unit” means a grouping of one or more Measures, as specified in Exhibit D of the Project Agreement.

Payments by Bonneville

Bonneville will pay Debt Service and Trustee Costs whether or not the Project or any portion thereof has been completed, terminated, is operating or operable, or its installation, use, or Energy Savings have been suspended, interrupted, interfered with, reduced, or curtailed or terminated in whole or in part, and such payments shall not be conditioned upon the performance or nonperformance of any Party to any agreement for any. cause whatever.

Project Implementation

The City agreed to make a good faith effort to produce a quantity of Completed Units that is generally consistent with the Implementation Plan. The City agrees to provide the Project's Energy Savings Achieved to Bonneville. Bonneville shall pay Annual Project Costs.

Reward and Penalty

Bonneville shall pay a reward to the City if the Levelized Project Cost is less than the Regional Levelized Cost. The City shall pay Bonneville a penalty if the Levelized Project Cost exceeds the greater of 22 mills per kWh or 110% of the Regional Average Levelized Cost, all as provided in the Project Agreement.

Arbitration

Either Party may elect to submit to binding arbitration most disputes arising out of the Project that the Parties cannot otherwise resolve by discussions. Bonneville's obligation to pay Debt Service and Trustee Costs and disputes relating to the Bond Ordinance are not subject to binding dispute resolution.

Uncontrollable Force

Any obligation of a Party to perform under the Project Agreement, except an obligation to pay amounts due under the Project Agreement, shall be excused when such failure is due to an Uncontrollable Force.

Assignment

Each Party will not assign or transfer its rights or obligations under the Project Agreement except to an entity required or permitted under the Bond Ordinance or, so long as no Bonds are outstanding, to another entity with the written consent of the other Party.

Trustee as Third Party Beneficiary

The Trustee is designated a third party beneficiary of the Project Agreement for purposes of enforcing Bonneville's payment obligations.

Amendment of Agreement

The Project Agreement shall not be amended in any manner that would reduce payments pledged as security for the Bonds or extend the time of payments or materially impair or affect the rights of the Bond owners.

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