NEW ISSUE — BOOK-ENTRY ONLY

Series 2006-A Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, based on an analysis of existing laws, regulations, rulings and court decisions and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2006-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2006-A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. See "TAX MATTERS" herein.

Series 2006-B (Taxable) Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2006-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the Internal Revenue Code of 1986. See "TAX MATTERS" herein.

$841,850,000
Energy Northwest

$338,775,000 Project 1 Electric Revenue Refunding Bonds, Series 2006-A
$434,210,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-A
$54,760,000 Project 3 Electric Revenue Refunding Bonds, Series 2006-A

$9,160,000 Project 1 Electric Revenue Refunding Bonds, Series 2006-B (Taxable)
$4,420,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-B (Taxable)
$525,000 Project 3 Electric Revenue Refunding Bonds, Series 2006-B (Taxable)

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

The Series 2006-A Bonds and the Series 2006-B (Taxable) Bonds are being issued for the purpose of refunding certain Prior Lien Bonds and Electric Revenue Bonds heretofore issued by Energy Northwest in connection with Project 1, Columbia and Project 3, as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2006-A Bonds and Series 2006-B Bonds (together, the "2006 Bonds") will be issued in fully registered form, registered in the name of Cede & Co., as Registered Owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2006 Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the Registered Owner of the 2006 Bonds and nominee of DTC, references herein to holders or Registered Owners shall mean Cede & Co. and shall not mean the beneficial owners of the 2006 Bonds. Principal of the 2006 Bonds is payable at the principal office of The Bank of New York Trust Company, N.A., Seattle, Washington, as Trustee for the 2006 Bonds. Interest on the 2006 Bonds is payable semiannually on January 1 and July 1 of each year, commencing July 1, 2006, by check or draft of the Trustee. As long as Cede & Co. is the Registered Owner as nominee of DTC, payments on the 2006 Bonds will be made to such Registered Owner, and disbursement of such payments will be the responsibility of DTC and DTC Participants as described herein. See "DESCRIPTION OF THE 2006 BONDS – GENERAL – Book-Entry System; Transferability and Registration" and Appendix I - "BOOK-ENTRY SYSTEM" herein.

*Certain of the Series 2006-A Bonds are subject to redemption prior to maturity as set forth herein. The Series 2006-B (Taxable) Bonds are not subject to redemption prior to maturity. See "*DESCRIPTION OF THE 2006 BONDS - REDEMPTION*" herein.*

The 2006 Bonds are special revenue obligations of Energy Northwest, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the

Bonneville Power Administration

("Bonneville") from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The 2006 Bonds are payable as provided herein on a subordinated basis to the Prior Lien Bonds and do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power. Projects 1 and 3 and Columbia are separate projects of Energy Northwest, and each Series of 2006 Bonds is payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A - "THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE — See Inside Cover

The 2006 Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Preston Gates & Ellis LLP, Seattle, Washington, Bond Counsel to Energy Northwest, and to certain other conditions. Certain tax matters will be passed upon by Orrick Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville. Certain legal matters will be passed upon for Energy Northwest by its General Counsel and for Bonneville by its General Counsel and by its Special Counsel, Orrick Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters. It is expected that the 2006 Bonds will be available for delivery through the facilities of DTC on or about April 20, 2006.

Goldman, Sachs & Co. **Citigroup**

JPMorgan **Prager, Sealy & Co., LLC**

Seattle-Northwest Securities Corporation **UBS Investment Bank**

March 23, 2006

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2006-A BONDS

$338,775,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2007	$ 29,570,000	5.00%	3.55%	29270CLK9
2008	890,000	5.00	3.60	29270CLL7
2009	36,990,000	5.00	3.63	29270CLM5
2010	64,750,000	5.00	3.69	29270CLN3
2011	76,015,000	5.00	3.74	29270CLP8
2012	27,440,000	5.00	3.81	29270CLQ6
2013	19,155,000	5.00	3.91	29270CLR4
2014	19,655,000	5.00	3.98	29270CLS2
2015	28,160,000	5.00	4.04	29270CLT0
2016	24,990,000	5.00	4.09	29270CLU7
2017	11,160,000	5.00	4.14**	29270CLV5

$434,210,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2020	$ 28,585,000	5.00%	4.27%**	29270CLW3
2020	50,000,000	5.00	4.22	29270CLX1
2021	82,515,000	5.00	4.30**	29270CLY9
2022	86,630,000	5.00	4.32**	29270CLZ6
2023	90,965,000	5.00	4.34**	29270CMA0
2024	95,515,000	5.00	4.36**	29270CMB8

$54,760,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2008	$ 7,225,000	5.00%	3.60%	29270CMC6
2009	8,090,000	5.00	3.63	29270CMD4
2016	3,605,000	5.00	4.09	29270CME2
2017	17,920,000	5.00	4.14**	29270CMF9
2018	17,920,000	5.00	4.18**	29270CMG7

THE SERIES 2006-B (TAXABLE) BONDS

$9,160,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2007	$ 9,160,000	5.16%	5.16%	29270CMH5

$4,420,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2011	$ 4,420,000	5.23%	5.23%	29270CMJ1

$525,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2008	$ 525,000	5.21%	5.21%	29270CMK8

** Priced to the July 1, 2016 par call date.

ENERGY NORTHWEST
P.O. Box 968
Richland, Washington 99352
Telephone (509) 372-5000
Facsimile (509) 372-5649

Executive Board Members

Edward E. Coates, Chairman
Dan G. Gunkel, Vice Chairman
Roger C. Sparks, Secretary
Tim Sheldon, Assistant Secretary
Tom Casey
Vera Claussen

K.C. Golden
Jack Janda
Lawrence Kenney
Sid W. Morrison
David Remington

Administrative Staff

Chief Executive Officer/Chief Nuclear Officer	Joseph V. Parrish
Vice President, Nuclear Generation	Dale K. Atkinson
Vice President, Technical Services	W. Scott Oxenford
Vice President, Energy/Business Services/Public Information Officer	John W. Baker
Vice President, Corporate Services/General Counsel/Chief Financial Officer	Albert E. Mouncer
Vice President, Organizational Performance and Staffing/Chief Knowledge Officer	Cheryl M. Whitcomb

Financial Advisor
Public Financial Management, Inc.

Bond Counsel
Preston Gates & Ellis LLP

Trustee for the 2006 Bonds
The Bank of New York Trust Company, N.A.

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
Portland, Oregon 97208
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Administrator and Chief Executive Officer	Stephen J. Wright
Deputy Administrator and Deputy Chief Executive Officer	Steven G. Hickok
Chief Operating Officer	Ruth B. Bennett
General Counsel	Randy A. Roach
Chief Financial Officer	David J. Armstrong

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

No dealer, broker, salesman or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and, if given or made, such other information or representations must not be relied upon as having been authorized by Energy Northwest or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy by, nor shall there be any sale of the 2006 Bonds to, any person in any jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

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

None of the information herein was provided by the Participants or the Trustee and none of such entities participated in the preparation of this Official Statement. This Official Statement has not been submitted to such entities for review, comment or approval.

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

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

IN CONNECTION WITH THE OFFERING OF THE 2006 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2006 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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$841,850,000

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$9,160,000 Project 1 Electric Revenue Refunding Bonds, Series 2006-B (Taxable)

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$525,000 Project 3 Electric Revenue Refunding Bonds, Series 2006-B (Taxable)

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover pages hereof and the appendices hereto, in connection with the sale of the 2006 Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the 2006 Bonds and is qualified in all respects by the more detailed information set forth elsewhere in this Official Statement. Unless otherwise specifically defined, certain capitalized terms used in this Introduction have the meanings given to such terms elsewhere in this Official Statement.

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington (formerly known as the Washington Public Power Supply System), proposes to issue $338,775,000 Project 1 Electric Revenue Refunding Bonds, Series 2006-A (the "Project 1 2006-A Bonds"), $434,210,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-A (the "Columbia 2006-A Bonds"), $54,760,000 Project 3 Electric Revenue Refunding Bonds, Series 2006-A (the "Project 3 2006-A Bonds," and together with the Project 1 2006-A Bonds and the Columbia 2006-A Bonds, the "Series 2006-A Bonds"), $9,160,000 Project 1 Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Project 1 2006-B (Taxable) Bonds"), $4,420,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Columbia 2006-B (Taxable) Bonds") and $525,000 Project 3 Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Project 3 2006-B (Taxable) Bonds," and together with the Project 1 2006-B (Taxable) Bonds and the Columbia 2006-B (Taxable) Bonds, the "Series 2006-B (Taxable) Bonds"). The Series 2006-A Bonds and Series 2006-B (Taxable) Bonds are together referred to herein as the "2006 Bonds."

The Project 1 2006-A Bonds are being issued pursuant to Chapters 39.46, 39.53 and 43.52 of the Revised Code of Washington, as amended (the "Act") and Resolution No. 835, adopted on November 23, 1993 (as amended and supplemented, the "Project 1 Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness of Energy Northwest, including certain indebtedness currently outstanding under Resolution No. 769, adopted September 18, 1975 (as amended and supplemented the "Project 1 Prior Lien Resolution") and certain indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution. The Project 1 2006-B (Taxable) Bonds (together with the Project 1 2006-A Bonds, the "Project 1 2006 Bonds") are being issued pursuant to the Act and the Project 1 Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the Project 1 2006 Bonds. Bonds issued pursuant to the Project 1 Prior Lien Resolution are referred to herein as the "Project 1 Prior Lien Bonds," and bonds issued pursuant to the Project 1 Electric Revenue Bond Resolution are referred to herein as the "Project 1 Electric Revenue Bonds."

The Columbia 2006-A Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted on October 23, 1997 (as amended and supplemented, the "Columbia Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness of Energy Northwest, including indebtedness currently outstanding under Resolution No. 640, adopted June 26, 1973 (as amended and supplemented, the "Columbia Prior Lien Resolution") and certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution. The Columbia 2006-B (Taxable) Bonds (together with the Columbia 2006-A Bonds, the "Columbia 2006 Bonds") are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the Columbia 2006-A Bonds and the Columbia 2006-B (Taxable) Bonds. Bonds issued pursuant to the Columbia Prior Lien Resolution are referred to herein as the "Columbia Prior Lien Bonds," and bonds issued pursuant to the Columbia Electric Revenue Bond Resolution are referred to herein as the "Columbia Electric Revenue Bonds."

The Project 3 2006-A Bonds are being issued pursuant to the Act and Resolution No. 838 adopted on November 23, 1993 (as amended and supplemented, the "Project 3 Electric Revenue Bond Resolution," and together with the Project 1 Electric Revenue Bond Resolution and the Columbia Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions") for the purpose of refunding certain indebtedness of Energy Northwest, including certain indebtedness currently outstanding under Resolution No. 775, adopted on December 3, 1975 (as amended and supplemented, the "Project 3 Prior Lien Resolution," and together with the Project 1 Prior Lien Resolution and the Columbia Prior Lien Resolution, the "Prior Lien Resolutions") and certain indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution. The Project 3 2006-B (Taxable) Bonds (together with the Project 3 2006-A Bonds, the "Project 3 2006 Bonds") are being issued pursuant to the Act and the Project 3 Electric Revenue Bond Resolution to pay certain costs of issuance and other refunding costs relating to the Project 3 2006 Bonds. Bonds issued pursuant to the Project 3 Prior Lien Resolution are referred to herein as the "Project 3 Prior Lien Bonds," and together with the Project 1 Prior Lien Bonds and the Columbia Prior Lien Bonds are collectively referred to herein as the "Prior Lien Bonds." Bonds issued pursuant to the Project 3 Electric Revenue Bond Resolution are referred to herein as the "Project 3 Electric Revenue Bonds," and together with the Project 1 Electric Revenue Bonds and the Columbia Electric Revenue Bonds are collectively referred to herein as the "Electric Revenue Bonds."

The Prior Lien Bonds, the Electric Revenue Bonds, including the 2006 Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Subordinated Resolutions are collectively referred to herein as the "Net Billed Bonds."

It is expected that Energy Northwest will offer its Columbia Generating Station Electric Revenue Bonds, Series 2006-C (the "Columbia 2006-C Bonds") and the Columbia Generating Station Electric Revenue Bonds, Series 2006-D (Taxable) (the "Columbia 2006-D (Taxable) Bonds," and together with the Columbia 2006-C Bonds, the "Columbia 2006-C and 2006-D Bonds") for sale on or after April 12, 2006, but all Series 2006-A Bonds, Series 2006-B (Taxable) Bonds and Columbia 2006-C and 2006-D Bonds will be issued on the same date.

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

ENERGY NORTHWEST

Energy Northwest was organized in 1957 as the Washington Public Power Supply System. By resolution of its Executive Board adopted on June 2, 1999, the Washington Public Power Supply System officially changed its name to Energy Northwest. It currently has 19 members, consisting of 16 public utility districts and the cities of Richland, Seattle and Tacoma, all located in the State of Washington. Energy Northwest has the authority, among other things, to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power and energy and to issue bonds and other evidences of indebtedness to finance the same.

Energy Northwest owns and operates a nuclear electric generating station, the Columbia Generating Station ("Columbia Generating Station" or "Columbia"), with a net design electric rating of 1,153 megawatts. Energy Northwest also owns an operating hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), with a net design electric rating of 27.5 megawatts. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 49 turbines with a maximum generating capacity of approximately 64 megawatts. Energy Northwest also owns and/or has financial responsibility for four other nuclear electric generating projects which have been terminated: Energy Northwest Nuclear Project No. 1 ("Project 1"), Energy Northwest Nuclear Project No. 3 ("Project 3") and Energy Northwest Nuclear Projects Nos. 4 and 5 ("Projects 4 and 5"). Projects 1 and 3 were terminated in 1994 and Projects 4 and 5 were terminated in 1982. For discussions concerning the termination of Projects Nos. 1, 3, 4 and 5, see "ENERGY NORTHWEST - PROJECT 1," "- PROJECT 3," and "- PROJECTS 4 and 5" in this Official Statement. Projects 1 and 3 and Columbia are collectively referred to herein as the "Net Billed Projects." Each of Projects 1 and 3 and Columbia is financed and accounted for as a separate utility system. Projects 4 and 5 were financed and accounted for as a single utility system separate and apart from all other Energy Northwest projects. All of Energy Northwest's projects are located in the State of Washington. For additional information relating to Energy Northwest, see "ENERGY NORTHWEST" in this Official Statement.

The United States of America, Department of Energy ("DOE"), acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), has acquired the capability of Projects 1 and 3 and Columbia. As more fully discussed under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS," Bonneville pays Energy Northwest for such capability pursuant to Net Billing Agreements (hereinafter defined), with payments being made through a combination of credits against customer bills and cash payments from the Bonneville Fund (hereinafter defined). Bonneville's obligations to make such payments under the Net Billing Agreements continue notwithstanding suspension or termination of any of Projects 1 or 3 or Columbia.

THE BONNEVILLE POWER ADMINISTRATION

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

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 31 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally-owned projects, including the Columbia Generating Station. Bonneville sells and/or exchanges power under contracts with over 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.

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 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 eleven million people. Electric power sold by Bonneville accounts for about 40% 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 2006 BONDS

The Project 1 2006 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2006 Bonds are secured, on a subordinated basis to the Project 1 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2006 Bonds are secured on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Columbia 2006 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2006 Bonds are secured, on a subordinated basis to the Columbia Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership and operation of Columbia. The Columbia 2006 Bonds are secured on a parity with the Columbia Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

The Project 3 2006 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2006 Bonds are secured, on a subordinated basis to the Project 3 Prior Lien Bonds, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2006 Bonds are secured on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are secured pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Subordinated Resolution described under "SECURITY FOR THE NET BILLED BONDS - ADDITIONAL INDEBTEDNESS."

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

Energy Northwest has covenanted that it will not issue any more Prior Lien Bonds or any other bonds, warrants or other obligations that will rank on a parity with the pledge of and lien on the revenues created by the Prior Lien Resolutions.

The 2006 Bonds are secured on a subordinated basis to the Prior Lien Bonds from amounts derived pursuant to Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The receipts, income and revenues derived from a Project secure only the 2006 Bonds relating to that Project. Accordingly, the owners of the 2006 Bonds issued for a particular Project will have no claim on the receipts, income and revenues securing any other Energy Northwest Project. For further information, see "SECURITY FOR THE NET BILLED BONDS" in this Official Statement.

For further information on the Net Billed Bonds outstanding as of March 1, 2006, see "ENERGY NORTHWEST - ENERGY NORTHWEST INDEBTEDNESS" in this Official Statement.

NET BILLING AGREEMENTS

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

Under the Net Billing Agreements, payments to Energy Northwest have not been made directly by Bonneville, but rather by the Participants. Such payments by the Participants are to be made in accordance with each Participant's participation in the purchase of the capability of the Net Billed Project. Bonneville pays for the capability of the Net Billed Project assigned by the Participants to it by crediting (or net billing) Bonneville's bills to Participants for power and other services purchased by Participants from Bonneville by the amount of the payment required to be made by the Participants to Energy Northwest. To the extent that the total amount of Bonneville's bills to each Participant (and consequently the amount of such credit available) over a contract year (July 1 to June 30) is less than the payment required to be made by the Participant to Energy Northwest, Bonneville is obligated to pay the deficiency in cash to the Participant from the Bonneville Fund. In the opinion of Bonneville's General Counsel, under Federal statutes Bonneville may only make payments to the United States Treasury from net proceeds; all cash payment obligations of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. Net proceeds are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (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.

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 Net Billed Project output or termination of the related Net Billed Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

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

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Proposed Direct Pay Agreements," Energy Northwest and Bonneville expect to execute an agreement with respect to each Net Billed Project pursuant to which Bonneville will agree to pay at least monthly all costs for each Net Billed Project directly to Energy Northwest. One effect of the Direct Payment Agreements will be that each Participant will pay Bonneville directly all costs associated with the Participant's contracts with Bonneville. The Direct Pay Agreements will not amend the Net Billing Agreements.

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

DESCRIPTION OF THE 2006 BONDS

GENERAL

The 2006 Bonds will initially be dated the date of delivery and will mature on July 1 in the years and bear interest, payable on January 1 and July 1 of each year, commencing July 1, 2006, at the rates shown on the inside cover of this Official Statement. Interest on the 2006 Bonds will be calculated based on a 360-day year, consisting of twelve 30-day months. The Bank of New York Trust Company, N.A., Seattle, Washington, has been appointed the Trustee, Paying Agent and Registrar for the 2006 Bonds (collectively, the "Trustee"). For so long as the 2006 Bonds are registered in the name of Cede & Co. (as nominee of The Depository Trust Company, New York, New York ("DTC")) or its registered assigns, payments of principal and interest shall be made in accordance with the operational arrangements of DTC. In the event that the 2006 Bonds are no longer registered in the name of Cede & Co., interest on the 2006 Bonds is payable by check or draft mailed to the Registered Owners thereof by the Trustee at the addresses appearing on the registration books on the 15th day of the month preceding the interest payment date, provided, however, that upon the written request of a Registered Owner of at least $1,000,000 in aggregate principal amount of a Series of the 2006 Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. Principal of the 2006 Bonds is payable at the office of the Trustee in Seattle, Washington.

Book-Entry System; Transferability and Registration

The 2006 Bonds will be available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the 2006 Bonds will not receive certificates representing their interests in such 2006 Bonds purchased, except as described in Appendix I - "BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as securities depository ("Securities Depository") for each Series of 2006 Bonds. As discussed in Appendix I - "BOOK-ENTRY SYSTEM," transfers of ownership interests in the 2006 Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the 2006 Bonds. Energy Northwest, the Trustee and any other person may treat the Registered Owner of any 2006 Bond as the absolute owner of such 2006 Bond for the purpose of making payment thereof and for all other purposes, and Energy Northwest and the Trustee shall not be bound by any notice or knowledge to the contrary, whether such 2006 Bond shall be overdue or not. All payments of or on account of interest or principal to any Registered Owner of any such 2006 Bond shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such 2006 Bond, to the extent of the sum or sums paid.

When 2006 Bonds are registered in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Trustee shall have no responsibility or obligation to any DTC Participant (as defined in Appendix I - "BOOK-ENTRY SYSTEM") or to any person on behalf of whom a DTC Participant holds an interest in the 2006 Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2006 Bonds, (2) the delivery to any DTC Participant or any other person, other than a Registered Owner as shown on the Bond Register, of any notice with respect to the 2006 Bonds, including any notice of redemption, (3) the payment to any DTC Participant or any other person, other than a Registered Owner as shown on the bond register, of any amount with respect to principal of, premium, if any, or interest on the 2006 Bonds, (4) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2006 Bonds, (5) any consent given or action taken by DTC as Registered Owner, or (6) any other matter. Energy Northwest and the Trustee may treat and consider Cede & Co., in whose name each 2006 Bond is registered, as the holder and absolute owner of such 2006 Bond for the purpose of payment, giving notices of redemption and other matters.

Discontinuation of Book-Entry Transfer System

If Energy Northwest determines to discontinue the book-entry system of transfer, Energy Northwest is required to execute, authenticate and deliver at no cost to the beneficial owners of the 2006 Bonds, 2006 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2006 Bonds shall be payable upon due presentment and surrender thereof at the principal office of the Trustee, and interest on the 2006 Bonds will be payable by check or draft mailed to the persons in whose names such 2006 Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date. If the book-entry transfer system for the 2006 Bonds is discontinued, registered ownership of any 2006 Bond may be transferred or exchanged by surrendering such Bond to the Trustee, with the assignment form appearing on the Bond duly executed. The Trustee shall not be required to transfer any 2006 Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

The Project 1 2006-A Bonds maturing on July 1, 2017 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2016, in whole or in part at any time (in such order of maturity as is selected by Energy Northwest and within a maturity in such manner as DTC or the Trustee, as appropriate, shall determine) at a redemption price equal to the principal amount of such Bonds to be redeemed, together with accrued interest to the redemption date.

The Columbia 2006-A Bonds maturing on July 1, 2020 (CUSIP No. 29270CLW3) and the Columbia 2006-A Bonds maturing on and after July 1, 2021 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2016, in whole or in part at any time (in such order of maturity as is selected by Energy Northwest and within a maturity in such manner as DTC or the Trustee, as appropriate, shall determine) at a redemption price equal to the principal amount of such Bonds to be redeemed, together with accrued interest to the redemption date.

The Project 3 2006-A Bonds maturing on and after July 1, 2017 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2016, in whole or in part at any time (in such order of maturity as is selected by Energy Northwest and within a maturity in such manner as DTC or the Trustee, as appropriate, shall determine) at a redemption price equal to the principal amount of such Bonds to be redeemed, together with accrued interest to the redemption date.

The Columbia 2006-A Bonds maturing on July 1, 2020 (CUSIP Number 29270CLX1) and the Series 2006-B (Taxable) Bonds are not subject to redemption prior to maturity.

Partial Redemption

If less than all of the Series 2006-A Bonds are to be so redeemed, Energy Northwest may select the maturity or maturities to be redeemed. If less than all of the Series 2006-A Bonds of any such maturity are to be redeemed the Series 2006-A Bonds or portions thereof to be redeemed are to be selected by the Trustee in such manner as the Trustee in its discretion may deem fair and appropriate. The Resolution provides that the portion of any Series 2006-A Bonds of a denomination of more than

$5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such Series 2006-A Bonds for redemption, the Trustee will treat each such Series 2006-A Bonds as representing that number of such Series 2006-A Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2006-A Bonds to be redeemed in part by $5,000.

Notice of Redemption

Notice of redemption of any 2006 Bonds is to be given by the Trustee by first-class mail not less than 30 days nor more than 60 days before the redemption date to the Registered Owners of the 2006 Bonds which are to be redeemed at their last addresses shown on the registration books for the 2006 Bonds. Such notice shall be deemed conclusively to be received by the Registered Owners of the 2006 Bonds which are to be redeemed, whether or not such notice is actually received. Mailing of such notice of redemption shall not be a condition precedent to such redemption, and failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the 2006 Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the 2006 Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if moneys sufficient for the redemption of the 2006 Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee for such 2006 Bonds on the redemption date and the 2006 Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. Energy Northwest may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry system is in effect with respect to the 2006 Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the 2006 Bonds of a maturity are to be redeemed, DTC or its successor and Participants and Indirect Participants (as such terms are defined in Appendix I - "BOOK-ENTRY SYSTEM") will determine the particular ownership interests of 2006 Bonds to be redeemed. Any failure of DTC or its successor or a Participant or Indirect Participant to do so, or to notify a Beneficial Owner of a 2006 Bond of any redemption, will not affect the sufficiency or the validity or the redemption of 2006 Bonds.

Neither Energy Northwest, the Trustee, nor the Underwriters can give any assurance that DTC, the Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the 2006 Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any 2006 Bonds on the open market at any time and at any price.

DEFEASANCE

The liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions shall be fully discharged and satisfied as to any related 2006 Bond and such 2006 Bond shall no longer be deemed to be outstanding under the Electric Revenue Bond Resolutions when payment of principal of and premium, if any, on such related 2006 Bond, plus interest on such principal to the date thereof shall have been made or shall have been provided for by irrevocably depositing with the Trustee or a paying agent for such 2006 Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment, or (2) specified "defeasance obligations" maturing or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will assure the availability of sufficient money to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to such 2006 Bonds. Defeasance obligations are defined in RCW 39.53 and include direct obligations of the United States and certain obligations of United States agencies and instrumentalities and others as defined under "Government Obligations" in Appendix H-1. See Appendix H-1, "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Defeasance (Article XI)" for a discussion of defeasance of the 2006 Bonds.

As a condition to defeasing the Series 2006-B (Taxable) Bonds, Energy Northwest must deliver to the Trustee for the Series 2006-B (Taxable) Bonds either a ruling from the Internal Revenue Service or an opinion of counsel to the effect that the Beneficial Owners of the Series 2006-B (Taxable) Bonds will not recognize income, gain or loss for federal income tax purposes as a result of Energy Northwest's defeasance of such Series 2006-B (Taxable) Bonds and will be subject to federal income tax on the same amount and in the same manner and at the same time as would have been the case if such defeasance had not occurred.

PURPOSE OF ISSUANCE

REFUNDING PROGRAM

In 2000, Bonneville presented to Energy Northwest a proposal for a "Debt Optimization Program." As originally proposed, the Debt Optimization Program involved extending to 2018 the final maturity of outstanding Columbia Net Billed Bonds coming due prior to 2013 through a series of refunding bond issues. Implementing the Debt Optimization Program was 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. 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 and minimize costs to rate payers; and (3) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. See "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Program" in Appendix A.

In 2000, Energy Northwest, in response to the Bonneville proposal, adopted a Refunding Plan, which essentially adopted the Debt Optimization Program as proposed by Bonneville. The Refunding Plan also reaffirmed the historical debt service savings goals for any future refinancing of Projects 1 and 3 and Columbia Net Billed Bonds. A portion of the 2006 Bonds will be used to refinance outstanding bonds for debt service savings.

In 2001, at Bonneville's request to increase the scope of the Debt Optimization Program, Energy Northwest revised such 2000 Refunding Plan to increase the average life of outstanding Projects 1 and 3 Net Billed Bonds by extending the maturity of such Bonds through 2018 for any future refinancing of such Bonds. A portion of the Project 1 and Project 3 2006 Bonds are being issued for such purpose. An additional objective of the Refunding Plan is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville.

In January 2006, Energy Northwest and Bonneville approved a three-part debt issuance plan that supplements the prior Refunding Plan, as revised. This supplemental plan approves (i) refunding $105 million in Columbia bonds for the purpose of implementing the Debt Optimization Program, with the refunding bonds having maturities up to 2024, (ii) refunding up to $350 million in Columbia callable and noncallable advance refundable bonds, with the refunding bonds having maturities up to 2024, and (iii) bond issuances to finance new capital investments at the Columbia Generating Station with maturities up to 2024.

In furtherance of the Refunding Plan, as revised, in July 2005, Citibank, N.A. extended a line of credit to Energy Northwest for each of the Net Billed Projects pursuant to three separate Credit Agreements. Under the Project 1, Columbia and Project 3 Credit Agreements, Energy Northwest may borrow up to $49,635,000, $99,630,000 and $34,880,000, respectively, from time to time during the period from July 1, 2005 to June 30, 2006. Proceeds of advances made under a Credit Agreement may be applied to refinance a portion of the cost of the related Project by providing a portion of the funds necessary to refund principal and, in some cases, interest on certain Prior Lien Bonds maturing on July 1, 2006, issued to finance such Project. Energy Northwest's obligation to repay advances under a Credit Agreement is evidenced by a bond anticipation note (the "Note") authorized to be executed and delivered by Energy Northwest pursuant to the related Separate Subordinated Resolution. As of March 23, 2006, Energy Northwest had borrowed $37,226,250, $71,696,511 and $26,160,003 under the Project 1, Columbia and Project 3 Credit Agreements, respectively. Energy Northwest expects to borrow additional amounts prior to the issuance of the 2006 Bonds. Each Note is secured on a parity with Electric Revenue Bonds issued by Energy Northwest under the related Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Separate Subordinated Resolutions. A portion of the proceeds of the Series 2006-A Bonds is to be applied to pay the Notes.

In addition, Energy Northwest expects to enter into credit agreements with Citibank, N.A. in July 2006, substantially similar to the Credit Agreements entered into in 2005, for the purpose of extending the maturity of the Net Billed Bonds maturing in 2007.

REFUNDED OBLIGATIONS

The Project 1 2006-A Bonds are being issued for the purpose (directly or indirectly through repayment of the Project 1 Note) of refunding (i) $351,635,000 aggregate principal amount of the Project 1 Prior Lien Bonds, and (ii) $6,190,000 aggregate principal amount of the Project 1 Electric Revenue Bonds.

The Columbia 2006-A Bonds are being issued for the purpose (directly or indirectly through repayment of the Columbia Note) of refunding (i) $324,060,000 aggregate principal amount of the Columbia Prior Lien Bonds, and (ii) $130,875,000 aggregate principal amount of the Columbia Electric Revenue Bonds.

The Project 3 2006-A Bonds are being issued for the purpose (directly or indirectly through repayment of the Project 3 Note) of refunding (i) $50,740,000 aggregate principal amount of Project 3 Prior Lien Bonds, and (ii) $7,395,000 aggregate principal amount of Project 3 Electric Revenue Bonds.

The Project 1 2006-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 1 2006-A Bonds and Project 1 2006-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Project 1 Prior Lien Bonds and Project 1 Electric Revenue Bonds.

The Columbia 2006-B (Taxable) Bonds are being issued for the purpose of paying certain costs relating to the issuance of the Columbia 2006-A Bonds and Columbia 2006-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Columbia Prior Lien Bonds and Columbia Electric Revenue Bonds.

The Project 3 2006-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 3 2006-A Bonds and the Project 3 2006-B (Taxable) Bonds as well as certain costs relating to the refunding of certain of the Project 3 Prior Lien Bonds and Project 3 Electric Revenue Bonds.

A major portion of the proceeds of the Series 2006-A Bonds and the Series 2006-B (Taxable) Bonds and other available amounts will be used to purchase certain investment securities permitted by the Prior Lien Resolutions and the Electric

Revenue Bond Resolutions, respectively (the "Investment Securities"), maturing in such amounts and at such times as shall be sufficient, together with the interest to accrue thereon, to pay the principal or redemption price, if any, of all of the Prior Lien Bonds and Electric Revenue Bonds to be refunded as set forth in the table below and to pay interest on all Prior Lien Bonds and the fixed rate Electric Revenue Bonds to be refunded to the date of their retirement. Concurrently with such purchase of Investment Securities, Energy Northwest shall deposit such Investment Securities in separate trust funds established with the Bond Fund Trustee for each of the Series of Prior Lien Bonds and Electric Revenue Bonds to be refunded pursuant to escrow agreements between Energy Northwest and the Bond Fund Trustee for each of such Series of Prior Lien Bonds and Electric Revenue Bonds to be refunded. At the time of such deposit, Energy Northwest shall direct the Bond Fund Trustee for each of the Series of the Prior Lien Bonds and Electric Revenue Bonds to be redeemed, if any, to give notice of redemption of such Prior Lien Bonds and Electric Revenue Bonds.

The accuracy of (1) the arithmetical computations as to the adequacy of the principal of and interest on the Investment Securities, together with other available funds, to pay the principal or redemption price, if any, of the Prior Lien Bonds and Electric Revenue Bonds to be refunded and to pay interest on all Prior Lien Bonds and the fixed rate Electric Revenue Bonds to be refunded to the date of their retirement, and (2) the mathematical computations of the yields on the Series 2006-A Bonds and the adjusted yields on the Investment Securities acquired with the proceeds of the Series 2006-A Bonds will be verified by Bond Logistix LLC.

The Bonds authorized to be refunded with the proceeds of the 2006 Bonds are identified below.

Prior Lien Bonds to be Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Redemption/ Maturity Date	Redemption Price
1	1993B	$ 3,600,000	2006	5.50 %	July 1, 2006	N/A
1	1993C	1,800,000	2006	5.00	July 1, 2006	N/A
1	1996A	36,015,000	2006	6.00	July 1, 2006	N/A
1	1996A	37,970,000	2007	6.00	July 1, 2006	102%
1	1996A	36,590,000	2009	5.70	July 1, 2006	102%
1	1996A	55,700,000	2010	5.75	July 1, 2006	102%
1	1996A	66,945,000	2011	5.75	July 1, 2006	102%
1	1996A	18,475,000	2012	5.75	July 1, 2006	102%
1	1996C	455,000	2006	5.20	July 1, 2006	N/A
1	1996C	505,000	2008	5.375	July 1, 2006	102%
1	1996C	8,885,000	2010	5.50	July 1, 2006	102%
1	1996C	9,360,000	2011	5.50	July 1, 2006	102%
1	1996C	9,820,000	2012	5.50	July 1, 2006	102%
1	1996C	10,355,000	2013	5.60	July 1, 2006	102%
1	1996C	10,970,000	2014	5.60	July 1, 2006	102%
1	1996C	11,565,000	2015	5.50	July 1, 2006	102%
1	1996C	12,120,000	2016	5.50	July 1, 2006	102%
1	1996C	12,740,000	2017	5.50	July 1, 2006	102%
1	1997A	6,550,000	2006	6.00	July 1, 2006	N/A
1	1997B	1,025,000	2006	5.00	July 1, 2006	N/A
1	1998A	190,000	2006	5.50	July 1, 2006	N/A
Columbia	1990A	2,115,000	2006	7.25	July 1, 2006	N/A
Columbia	1991A	19,065,000*	2006	N/A	July 1, 2006	N/A
Columbia	1991A	9,695,000*	2007	N/A	July 1, 2007	N/A
Columbia	1992A	11,345,000	2006	6.10	July 1, 2006	N/A
Columbia	1993A	15,605,000	2006	5.70	July 1, 2006	N/A
Columbia	1993A	12,290,000**	2007	5.80	July 1, 2007	N/A
Columbia	1993B	16,215,000	2006	5.50	July 1, 2006	N/A
Columbia	1993B	17,085,000	2007	5.60	July 1, 2007	N/A
Columbia	1993B	6,030,000	2008	5.65	July 1, 2008	N/A
Columbia	1994A	10,545,000	2006	4.80	July 1, 2006	N/A
Columbia	1996A	19,185,000	2006	6.00	July 1, 2006	N/A
Columbia	1996A	16,500,000	2007	6.00	July 1, 2006	102%
Columbia	1996A	18,520,000	2009	5.60	July 1, 2006	102%
Columbia	1996A	19,430,000	2010	5.625	July 1, 2006	102%
Columbia	1996A	20,480,000	2011	5.70	July 1, 2006	102%
Columbia	1996A	54,045,000	2012	5.70	July 1, 2006	102%
Columbia	1997A	15,905,000	2010	5.10	July 1, 2007	102%
Columbia	1997A	16,770,000	2011	5.125	July 1, 2007	102%
Columbia	1997A	17,680,000	2012	5.20	July 1, 2007	102%
Columbia	1997B	5,000,000	2006	5.50	July 1, 2006	N/A
Columbia	1998A	555,000	2006	5.50	July 1, 2006	N/A
3	1993C	22,005,000	2006	5.00	July 1, 2006	N/A
3	1996A	6,905,000	2006	6.00	July 1, 2006	N/A
3	1996A	7,715,000	2008	5.60	July 1, 2006	102%
3	1996A	8,145,000	2009	5.70	July 1, 2006	102%
3	1997A	5,970,000	2006	5.00	July 1, 2006	N/A

* Value at maturity of Compound Interest Bonds.

** Maturity partially refunded.

Electric Revenue Bonds to be Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Redemption/ Maturity Date	Redemption Price
1	1993-1A	$ 6,190,000*	2006	variable	July 3, 2006	100%
Columbia	1997-2A	6,520,000*	2006	variable	July 5, 2006	100
Columbia	1997-2A	16,050,000*	2007	variable	July 5, 2006	100
Columbia	1997-2A	7,050,000*	2008	variable	July 5, 2006	100
Columbia	1997-2A	7,320,000*	2009	variable	July 5, 2006	100
Columbia	1997-2A	22,295,000*	2010	variable	July 5, 2006	100
Columbia	1997-2A	22,625,000*	2011	variable	July 5, 2006	100
Columbia	1997-2A	8,225,000*	2012	variable	July 5, 2006	100
Columbia	2003-A	5,305,000[(1)] **	2010	5.50%	July 1, 2010	N/A
Columbia	2003-A	6,775,000[(2)] **	2010	5.50	July 1, 2010	N/A
Columbia	2003-A	9,440,000**	2012	5.50	July 1, 2012	N/A
Columbia	2004-A	5,120,000**	2008	5.25	July 1, 2008	N/A
Columbia	2004-A	420,000**	2008	3.75	July 1, 2008	N/A
Columbia	2004-A	4,555,000**	2009	5.25	July 1, 2009	N/A
Columbia	2004-A	5,975,000**	2010	5.25	July 1, 2010	N/A
Columbia	2004-A	2,545,000[(3)] **	2011	5.25	July 1, 2011	N/A
Columbia	2004-A	655,000[(4)] **	2011	5.25	July 1, 2011	N/A
3	1993-3A	1,035,000*	2006	variable	July 3, 2006	100
3	1998-3A	6,360,000*	2006	variable	July 5, 2006	100

* Scheduled sinking fund redemption installment.
** Maturity partially refunded.
(1) CUSIP Number 29270CFA8.
(2) CUSIP Number 29270CFB6.
(3) CUSIP Number 29270CHQ1.
(4) CUSIP Number 29270CHR9.

NEW MONEY BONDS

The Columbia 2006-C Bonds and Columbia 2006-D (Taxable) Bonds are being issued to finance a portion of the costs incurred or planned to be incurred during fiscal years 2006 and 2007 for certain capital improvements at Columbia and to pay costs of issuance relating to such bonds. The capital improvements at Columbia include upgrading the Digital Electro Hydraulic Control System, replacing feedwater heaters, purchasing and loading spent fuel casks, replacing process radwaste monitors, procuring control rod blades and local power range monitors, replacement of the service water and reactor recirculation motors and pumps, replacement of numerous other pumps and motors, and replacement of various pieces of equipment.

ESTIMATED SOURCES AND USES OF FUNDS

SOURCES OF FUNDS:

Project 1	
Principal of Project 1 2006-A Bonds	$ 338,775,000
Principal of Project 1 2006-B (Taxable) Bonds	9,160,000
Net Original Issue Premium Project 1 Bonds	18,985,224
Moneys Available Under Project 1 Prior Lien Resolution	42,804,876
Total	$ 409,725,100
Columbia	
Principal of Columbia 2006-A Bonds	$ 434,210,000
Principal of Columbia 2006-B (Taxable) Bonds	4,420,000
Net Original Issue Premium Columbia Bonds	25,253,772
Moneys Available Under Columbia Prior Lien Resolution	76,656,939
Total	$ 540,540,711
Project 3	
Principal of Project 3 2006-A Bonds	$ 54,760,000
Principal of Project 3 2006-B (Taxable) Bonds	525,000
Net Original Issue Premium Project 3 Bonds	3,292,623
Moneys Available Under Project 3 Prior Lien Resolution	27,165,341
Total	$ 85,742,964

USES OF FUNDS:

Project 1	
Deposit with escrow trustee for refunded Project 1 Prior Lien Bonds	$ 364,235,318
Deposit with escrow trustees for refunded Project 1 Electric Revenue Bonds	6,130,335
Project 1 Note Repayment	37,226,250
Costs of Issuance*	2,133,197
Total	$ 409,725,100
Columbia	
Deposit with escrow trustee for refunded Columbia Prior Lien Bonds	$ 333,554,426
Deposit with escrow trustees for refunded Columbia Electric Revenue Bonds	132,583,938
Columbia Note Repayment	71,696,511
Costs of Issuance*	2,705,836
Total	$ 540,540,711
Project 3	
Deposit with escrow trustee for refunded Project 3 Prior Lien Bonds	$ 51,915,039
Deposit with escrow trustees for refunded Project 3 Electric Revenue Bonds	7,320,987
Project 3 Note Repayment	26,160,003
Costs of Issuance*	346,935
Total	$ 85,742,964

* Includes underwriters' compensation.

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2006 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 1, which pledge is subject, so long as any of the Project 1 Prior Lien Bonds remain outstanding ($820,190,000 of which were outstanding as of March 1, 2006), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2006 Bonds are a charge on the receipts, income and revenues of Project 1 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 1 Prior Lien Resolution and payments required to be made under the Project 1 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 1, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 1 2006 Bonds are also secured by a pledge of the proceeds of the sale of Project 1 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 1 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 1 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 1 Electric Revenue Bond Resolution, the Project 1 2006 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Project 1 Separate Subordinated Resolution. There were outstanding as of March 1, 2006, $1,151,660,000 principal amount of Project 1 Electric Revenue Bonds.

The Columbia 2006 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Columbia, which pledge is subject, so long as any of the Columbia Prior Lien Bonds remain outstanding ($766,965,000 of which were outstanding as of March 1, 2006), to the lien and pledge of the Columbia Prior Lien Resolution. The Columbia 2006 Bonds are a charge on the receipts, income and revenues of Columbia subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Columbia Prior Lien Resolution and payments required to be made under the Columbia Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Columbia, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Columbia 2006 Bonds are also secured by a pledge of the proceeds of the sale of Columbia Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Columbia Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Columbia Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Columbia Electric Revenue Bond Resolution, the Columbia 2006 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Columbia Separate Subordinated Resolution. There were outstanding as of March 1, 2006, $1,476,270,000 principal amount of Columbia Electric Revenue Bonds.

The Project 3 2006 Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 3 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 3, which pledge is subject, so long as any of the Project 3 Prior Lien Bonds remain outstanding ($738,500,000 of which were outstanding as of March 1, 2006), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2006 Bonds are a charge on the receipts, income and revenues of Project 3 subordinate to the payments to be made into the Bond Fund, the Fuel Fund and the Reserve and Contingency Fund established pursuant to the Project 3 Prior Lien Resolution and payments required to be made under the Project 3 Prior Lien Resolution with respect to Energy Northwest's cost of operating and maintaining Project 3, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 3 2006 Bonds are also secured by a pledge of the proceeds of the sale of Project 3 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 3 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 3 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 3 Electric Revenue Bond Resolution, the Project 3 2006 Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution or other obligations of Energy Northwest issued pursuant to any Project 3 Separate Subordinated Resolution. There were outstanding as of March 1, 2006, $1,183,665,000 principal amount of Project 3 Electric Revenue Bonds.

Energy Northwest has covenanted with the owners of the Electric Revenue Bonds that it will not issue any more Prior Lien Bonds or any other bonds, warrants or other obligations that will rank on a parity with the pledge of and lien on the revenues created by the related Prior Lien Resolution.

Amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 1 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 1 2006 Bonds, subject to the payments required in connection with the Project 1 Prior Lien Bonds as described in the following sentence. So long as any of the Project 1 Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Project 1 Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Project 1 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Project 1 Electric Revenue Bonds, including the Project 1 2006 Bonds. See "NET BILLING AND RELATED AGREEMENTS" below.

Amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements entered into among Energy Northwest, Bonneville and the Columbia Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Columbia 2006 Bonds, subject to the payments required in connection with the Columbia Prior Lien Bonds as described in the following sentence. So long as any of the Columbia Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Columbia Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Columbia Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Columbia Electric Revenue Bonds, including the Columbia 2006 Bonds. See "NET BILLING AND RELATED AGREEMENTS" below.

Amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 3 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 3 2006 Bonds, subject to the payments required in connection with the Project 3 Prior Lien Bonds as described in the following sentence. So long as any of the Project 3 Prior Lien Bonds remain outstanding, after making the monthly payments and deposits required by the Project 3 Prior Lien Resolution, Energy Northwest is obligated to pay to the Trustee for the Project 3 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements, amounts sufficient to pay the principal of and premium, if any, and interest on the Project 3 Electric Revenue Bonds, including the Project 3 2006 Bonds. See "NET BILLING AND RELATED AGREEMENTS" below.

Bonneville may make only such expenditures from the Bonneville Fund as shall have been included in budgets submitted annually to Congress. Bonneville includes in its annual budget submittal to Congress an amount sufficient to cover its obligations under the Net Billing Agreements, including the payment of debt service on the Net Billed Bonds. Bonneville may make such expenditures without further appropriation and without fiscal year limitation, but subject to such specific directives or limitations on use of the Bonneville Fund as may be included by Congress in appropriation acts. The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see Appendix A - "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - The Bonneville Fund" in this Official Statement.

The Project 1 2006 Bonds, the Columbia 2006 Bonds and the Project 3 2006 Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2006 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2006 Bonds and the Project 3 2006 Bonds. The owners of the Columbia 2006 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2006 Bonds and the Project 3 2006 Bonds. The owners of the Project 3 2006 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2006 Bonds and the Columbia 2006 Bonds. No Bondholder has a claim on the assets of any Project.

The 2006 Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power.

See Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

EVENTS OF DEFAULT AND REMEDIES

For a description of the events of default and remedies applicable to the Electric Revenue Bonds, including the 2006 Bonds, see Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Events of Default."

Under each Prior Lien Resolution, the happening of one or more of the following events constitutes an Event of Default: (i) default in the performance of any obligation with respect to payments into the respective Revenue Fund; (ii) default in the payment of the principal of and premium, if any, or default for 30 days in the payment of interest on any of the respective Prior Lien Bonds or any sinking fund installment on any of the respective Prior Lien Bonds; (iii) default for 90 days in the observance and performance of any other of the covenants, conditions and agreements of Energy Northwest in the respective Prior Lien Resolution; (iv) the sale or conveyance of any properties of the respective Net Billed Project except as permitted by the respective Prior Lien Resolution or the voluntary forfeiture of any license, franchise, permit or other privilege necessary or desirable in the operation of such Project; and (v) certain acts related to the insolvency or bankruptcy of Energy Northwest. Both the applicable Prior Lien Bond Fund Trustee and the holders of not less than 20% in aggregate principal amount of the respective Prior Lien Bonds then outstanding under the respective Prior Lien Resolution have the right to accelerate the maturity of such

Prior Lien Bonds after an Event of Default occurs under such Resolution. See Appendix H-2 - "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS - Events of Default; Remedies."

Under each Prior Lien Resolution, the covenants referred to in clause (iii) of the preceding paragraph include the following, among others: (a) completing construction of the respective Net Billed Project at the earliest practicable time, operating such Project and the business in connection therewith in an efficient manner and at reasonable cost, maintaining such Project in good condition and making all necessary and proper repairs, renewals and replacements, and (b) maintaining and collecting rates and charges for capability, power and energy and other services, facilities and commodities sold, furnished or supplied through such Project which will be adequate, whether or not the generation or transmission of power by such Project is suspended, interrupted or reduced for any reason whatsoever, to provide revenues sufficient, among other things, to pay the expenses of operating and maintaining such Project and the debt service on the related Prior Lien Bonds. See Appendix H-2 - "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS - Certain Covenants."

If the maturity of Prior Lien Bonds or Electric Revenue Bonds, including the 2006 Bonds, were accelerated by the applicable Bond Fund Trustee or Trustee or the holders of the requisite principal amount of such Bonds after an Event of Default under the respective Prior Lien Resolution or Electric Revenue Bond Resolution, no assurance can be given that the principal amount of the accelerated Prior Lien Bonds or Electric Revenue Bonds would be payable currently as a cost under the terms of the Net Billing Agreements related to such Net Billed Project. See "NET BILLING AND RELATED AGREEMENTS - Payment Procedures" and "SECURITY FOR THE NET BILLED BONDS - LIMITATIONS ON REMEDIES" for a discussion of the limitations of certain remedies. The Notes described under "PURPOSE OF ISSUANCE" are also subject to acceleration under the applicable Credit Agreements.

If Bonneville and the Participants were obligated only to provide funds to meet the scheduled amounts due on the respective Prior Lien Bonds and not the amounts due upon acceleration, moneys intended to be applied to the payment of the respective Electric Revenue Bonds would be applied by the applicable Prior Lien Bond Fund Trustee to payment of such Prior Lien Bonds, and the Electric Revenue Bonds would not be paid until such Prior Lien Bonds ceased to be outstanding or the Event of Default giving rise to such acceleration were cured.

See Appendix H-2 - "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS" for further information.

Payments and the provision of credits by Bonneville and payments by Participants under the Net Billing Agreements relating to Project 1, the Columbia Generating Station or Project 3, respectively, that are required to be made to Energy Northwest to pay the principal of and interest on the outstanding Net Billed Bonds issued for the related Net Billed Project are required to be made notwithstanding the occurrence of an Event of Default. If an Event of Default occurs under the related Prior Lien Resolution, whether or not such Event of Default gives rise to an acceleration of the Prior Lien Bonds outstanding under such Resolution, Energy Northwest is required under such Resolution to pay all revenues of such Project thereafter received by it upon demand to the applicable Prior Lien Bond Fund Trustee until all such Prior Lien Bonds have been paid in full or such Event of Default has been cured, whichever occurs first. In such event, moneys intended to be applied to the payment of related Electric Revenue Bonds would be paid instead to the applicable Prior Lien Bond Fund Trustee and such Electric Revenue Bonds would not be paid until such Prior Lien Bonds have been paid in full or such Event of Default has been cured, whichever occurs first.

LIMITATIONS ON REMEDIES

Upon the occurrence of an Event of Default under the Electric Revenue Bond Resolutions and Prior Lien Resolutions, payment of the principal of and interest on the 2006 Bonds may be accelerated. Any action to compel payment, for money damages or to accelerate payment would be subject to the limitations on legal claims and remedies against public bodies under Washington law. The right to accelerate payments by a Washington municipality has not been tested by any Washington court. Any remedies available to Bondholders are in many respects dependent upon judicial actions which are in turn often subject to discretion and delay and can be expensive and time-consuming to obtain. If Energy Northwest fails to comply with its covenants under the Electric Revenue Bond Resolutions or to pay principal of or interest on the 2006 Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the 2006 Bonds. See "SECURITY FOR THE NET BILLED BONDS - EVENTS OF DEFAULT AND REMEDIES" for a discussion of possible limits of amounts payable under the Net Billing Agreements in the event of acceleration of the Net Billed Bonds.

In addition to the limitations on remedies in the Electric Revenue Bond Resolutions, the rights and obligations under the 2006 Bonds may be limited by and are subject to bankruptcy, insolvency, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases. The opinions to be delivered by Preston Gates & Ellis LLP, as Bond Counsel, concurrently with the issuance of the 2006 Bonds, will be subject to limitations regarding such creditors' rights. See Appendix D-1 - "PROPOSED FORM OF OPINIONS OF BOND COUNSEL" and Appendix D-2 - "PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL," respectively.

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the 2006 Bonds. In the Electric Revenue Bond Resolutions, Energy Northwest has reserved the right to create a reserve account to secure a separate series of Electric Revenue Bonds.

ADDITIONAL INDEBTEDNESS

The Electric Revenue Bonds are subordinate to the Prior Lien Bonds. In each Electric Revenue Bond Resolution, Energy Northwest has reserved the right to issue, upon satisfaction of certain conditions set forth therein, additional bonds or notes under the Electric Revenue Bond Resolutions and under one or more separate resolutions ("Separate Subordinated Resolutions") of the Executive Board creating a pledge of and lien on the receipts, income and revenues derived from the related Project of equal rank with the pledge and lien created by such Electric Revenue Bond Resolution in favor of the Electric Revenue Bonds. Each Note that is to be paid from the proceeds of the Series 2006-A Bonds and the Series 2006-B (Taxable) Bonds and similar notes to be issued pursuant to credit agreements to be executed in 2006 have been or will be issued pursuant to Separate Subordinated Resolutions. There are no restrictions on or conditions to issuing debt on a parity with the Electric Revenue Bonds under the Electric Revenue Bond Resolutions, including the 2006 Bonds, pursuant to Separate Subordinated Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist under the applicable Electric Revenue Bond Resolution.

Conditions to the issuance of additional bonds pursuant to the Electric Revenue Bond Resolutions are described in Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

Each of the Electric Revenue Bond Resolutions permits the use of certain credit facilities to secure the payment of the related Electric Revenue Bonds and the incurrence by Energy Northwest of reimbursement obligations of the type referred to in such Electric Revenue Bond Resolution to reimburse the issuer of a credit facility. Each of the Electric Revenue Bond Resolutions also permits the use of interest rate exchange agreements or similar agreements. Such reimbursement obligations or obligations of Energy Northwest under such interest rate exchange agreements, including any termination payments owed by Energy Northwest, may be secured on a parity with the lien created by the Electric Revenue Bond Resolutions in favor of the related Electric Revenue Bonds. See Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

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

NET BILLING AND RELATED AGREEMENTS

General

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its ownership share of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (the "Project 3 Net Billing Agreements," which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Under the Net Billing Agreements, each Participant assigned its share of the capability of the Net Billed Project to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project. See Appendix F - "ENERGY NORTHWEST PARTICIPANT UTILITY SHARE OF FISCAL YEAR 2006 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2006 Budgets.

Under the Net Billing Agreements, in payment for the share of the capability of each Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement referred to below under "NET BILLING AND RELATED AGREEMENTS - Payment Procedures." Bonneville is obligated to pay this amount to such Participant by providing net billing credits against the amounts such Participant owes Bonneville under the Participant's power sales and other contracts with Bonneville and by making the cash payments described below (subject to the limitations described herein under Appendix A - "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - The Bonneville Fund"). Each Participant is obligated to pay Energy Northwest an amount equal to the amount of such credits and cash payments as payment on account of its obligations to pay for its share of the Net Billed Project capability.

The Net Billing Agreements provide for cash payments and the provision of credits by Bonneville and payments by Participants whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Net Billed Project output or termination of the related Net Billed

Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

The Net Billing Agreements require each Participant to pay Energy Northwest the amount set forth in its Billing Statement or accounting statement. Each Participant is required to make payments to Energy Northwest only from revenues derived by the Participant from the ownership and operation of its electric utility properties and from payments made by Bonneville under the Net Billing Agreements. Each Participant has covenanted that it will establish, maintain and collect rates or charges for power and energy and other services furnished through its electric utility properties which shall be adequate to provide revenues sufficient to make required payments to Energy Northwest under the Net Billing Agreements and to pay all other charges and obligations payable from or constituting a charge and lien upon such revenues.

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

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

By letter dated August 1, 1989 (the "1989 Letter Agreement"), Bonneville agreed with Energy Northwest that, in the event any Participant shall be unable for any reason, or shall fail or refuse, to pay to Energy Northwest any amount due from such Participant under its Net Billing Agreement for which a net billing credit or cash payment to such Participant has been provided by Bonneville, Bonneville will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the Net Billing Agreements.

As described under "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS - Proposed Direct Pay Agreements," Energy Northwest and Bonneville expect to execute an agreement with respect to each Net Billed Project pursuant to which Bonneville will agree to monthly pay all costs for each Net Billed Project directly to Energy Northwest and each Participant will pay Bonneville directly all costs associated with the Participant's contracts with Bonneville.

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

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

Payment Procedures

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

In the month preceding the beginning of each contract year and in each month thereafter, Bonneville renders a bill to each Participant for power and other services under the Participant's power sales and other contracts with Bonneville. In the first month of the contract year, that bill shows an offsetting credit equal to the full amount of such bill to the extent of the

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

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

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

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

Post Termination Agreements

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

Assignment of Participant Shares

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

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

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

Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants

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

Assignment Agreements

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

Proposed Direct Pay Agreements

Energy Northwest and Bonneville expect to execute an agreement with respect to each Net Billed Project ("Direct Pay Agreements") pursuant to which, beginning May 2006, Bonneville will agree to pay at least monthly all costs for each Net Billed Project, including debt service on the Net Billed Bonds, directly to Energy Northwest. Each Participant would pay directly to Bonneville all costs associated with its power sales and other contracts with Bonneville instead of making such payments to Energy Northwest. The Net Billing Agreements provide that Energy Northwest is to bill budgeted costs less amounts payable from sources other than the Net Billing Agreements to Participants. Direct payments received from Bonneville under the Direct Pay Agreements will be considered a source other than the Net Billing Agreements and, therefore, the Net Billing Agreements are not being amended. In the Direct Pay Agreements, Energy Northwest will agree to promptly bill each Participant its share of the costs of the respective Project under the Net Billing Agreements if Bonneville fails to make a payment when due under the Direct Pay Agreements. While the payments to Energy Northwest under the proposed Direct Pay Agreements would be included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements would not be pledged to the payment of the related series of Net Billed Bonds and would be subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest. If the Direct Pay Agreements were terminated, Bonneville and Energy Northwest would return to the payment procedures described under "Payment Procedures" above. See "SECURITY FOR THE NET BILLED BONDS – Pledge of Revenues and Priority," and Appendix A - "BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - Order in Which Bonneville's Costs Are Met."

Other Net Billing Obligations

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

Bonneville is authorized to enter into additional contracts providing for net billing or similar credits. The Net Billing Agreements provide that Bonneville and each Participant shall not enter into any agreement providing for net billing if

Bonneville estimates that, as a result of such agreement, the aggregate of its billings to such Participant will be less than 115% of Bonneville's net billing obligations to such Participant under all agreements between Bonneville and such Participant providing for net billing. Bonneville has no present plans to enter into new agreements requiring net billing with Participants.

THE BONNEVILLE FUND

The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses, including its cash payments to provide for that amount, if any, due under the Net Billing Agreements which is not paid from net billing credits. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see Appendix A - "THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS - The Bonneville Fund."

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

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

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System (as defined in Appendix A - "THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (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 amounts appropriated to the Corps and the Bureau for 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 2005 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 other than to the United States Treasury, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may only make payments to the United States Treasury from net proceeds; all other cash payments of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its 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.

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) Net Billed Project costs and Trojan Nuclear Project costs to the extent covered by net billing credits, (2) cash payments out of the Bonneville Fund to cover all required payments incurred by Bonneville pursuant to law, including net billing cash payments and payments under the Direct Pay Agreements, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury. Once the Direct Pay Agreements are effective, the costs of the Net Billed Projects will be covered through such agreements rather than by net billing credits.

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

Bonneville's obligation under the Project 1 Net Billing Agreements is to pay an amount equal to the costs of Project 1 less any other funds which shall be specified in the Annual Budget as payable from sources other than the payments to be made under the Net Billing Agreements. Similar language is found in the Net Billing Agreements for Columbia and Project 3. In the opinion of Bonneville's General Counsel, this provision would permit Bonneville to make payments on account of debt service on all Net Billed Bonds for a Net Billed Project directly to the applicable Bond Fund Trustee or Trustee. Such payment would be made only pursuant to an agreement with the applicable Bond Fund Trustee or Trustee requiring Bonneville to make such payment directly to the applicable Bond Fund Trustee or Trustee on or before the date such amounts would be required to be paid by Energy Northwest to the applicable Bond Fund Trustee or Trustee under the applicable Net Billed Resolution. Bonneville has no present intention of undertaking such actions. The effect of such an agreement would be to reduce the amount of costs included in the Annual Budget for the Net Billed Project to be paid under the Net Billing Agreements by the amount of the debt service payable directly by Bonneville to the applicable Bond Fund Trustee or Trustee.

For further information see Appendix A - “THE BONNEVILLE POWER ADMINISTRATION - BONNEVILLE FINANCIAL OPERATIONS.”

ENERGY NORTHWEST

GENERAL

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

Energy Northwest owns and operates Columbia and Packwood, which are currently in operation, and have net design electric ratings of 1,153 megawatts and 27.5 megawatts, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, consisting of 49 wind turbines with a maximum generating capacity of approximately 64 megawatts. Energy Northwest also owns and/or has financial responsibility for four nuclear electric generating projects that have been terminated: Projects 1, 3, 4 and 5. For discussions concerning the termination of Projects 1, 3, 4 and 5, see “- Project 1,” “- Project 3” and “- Projects 4 and 5.”

Each of Energy Northwest’s projects is treated and accounted for by Energy Northwest as a separate utility system, with the exception of Projects 4 and 5, which together comprised a single utility system. Under Washington law, a joint operating agency may create separate special funds for each of its utility systems and Energy Northwest has done so. The resolutions of Energy Northwest pursuant to which its various series of bonds are issued provide that the income, receipts and revenues of each utility system are pledged solely to the payment of obligations incurred in connection with that utility system. See Appendix C - “AUDITED FINANCIAL STATEMENTS OF ENERGY NORTHWEST PROJECTS FOR THE YEAR ENDED JUNE 30, 2005” for the audited financial statements of each of Energy Northwest’s projects, including the report of the independent auditors, PricewaterhouseCoopers LLP, for the fiscal year ended June 30, 2005.

ENERGY NORTHWEST INDEBTEDNESS

The following table sets forth the principal amounts of revenue bonds and refunding revenue bonds issued by Energy Northwest and outstanding as of March 1, 2006. For information with respect to certain outstanding Notes of Energy Northwest and Net Billed Bonds to be refunded see "PURPOSE OF ISSUANCE."

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF MARCH 1, 2006

REVENUE BONDS	**PRINCIPAL AMOUNT**
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 820,190,000
Electric Revenue Refunding Bonds	1,151,660,000
TOTAL PROJECT 1	$ 1,971,850,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 766,965,000 (1)
Electric Revenue Refunding Bonds	1,316,430,000
Electric Revenue Bonds	159,840,000
TOTAL COLUMBIA	$ 2,243,235,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 738,500,000 (1)
Electric Revenue Refunding Bonds	1,183,665,000
TOTAL PROJECT 3	$ 1,922,165,000
TOTAL NET BILLED REVENUE BONDS	$ 6,137,250,000
Packwood Revenue Bonds (2)	$ 3,161,000
Nine Canyon Wind Project Revenue Bonds (2)	$ 89,960,000

(1) Includes $24,717,000 accreted value of Compound Interest Bonds for Columbia and $292,603,000 accreted value of Compound Interest Bonds for Project 3 each as of June 30, 2005.

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

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 19, consisting of 16 public utility districts and the cities of Richland, Seattle, and Tacoma, all located in the State of Washington. Any public utility district and any municipal entity within the State of Washington authorized to engage in the business of generating or distributing electricity may join Energy Northwest.

Energy Northwest has its principal office in Richland, Washington. The Board of Directors of Energy Northwest is comprised of 19 utility members, one from each of the member utilities. Pursuant to the Act, the powers and duties of the Board of Directors are limited to (i) final authority on any decision to acquire, construct, terminate or decommission any power plants, works and facilities, except that once such a final decision is made with respect to a nuclear power plant, the Executive Board has authority to make all subsequent decisions regarding such plant; (ii) the election and removal of, and establishment of salaries for, the five members of the Executive Board selected from among the members of the Board of Directors; and (iii) the selection of three of the six members of the Executive Board who are outside directors. All other powers and duties of Energy Northwest, including but not limited to the authority to sell any power plant, works and facilities, are vested in the Executive Board.

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

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

EXECUTIVE BOARD

Present Executive Board members are listed below.

Name	Occupation	Term Expires
Edward E. Coates, Chairman	Retired Utility Executive	June 2006
Dan G. Gunkel, Vice Chairman	Public Utility District Commissioner	June 2006
Roger C. Sparks, Secretary	Public Utility District Commissioner	June 2006
Tim Sheldon, Assistant Secretary	Washington State Senator	June 2008
Tom Casey	Public Utility District Commissioner	June 2006
Vera Claussen	Public Utility District Commissioner	June 2006
K.C. Golden	Executive	June 2009
Jack Janda	Public Utility District Commissioner	June 2006
Lawrence Kenney	Retired Organized Labor Executive	June 2006
Sid W. Morrison	Retired Executive	June 2009
David Remington	Financial Consultant	June 2008

MANAGEMENT

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

Name	Position	Nuclear Industry Experience
Joseph V. Parrish	Chief Executive Officer/Chief Nuclear Officer	35 years
Dale K. Atkinson	Vice President, Nuclear Generation	28 years
W. Scott Oxenford	Vice President, Technical Services	22 years
John W. Baker	Vice President, Energy/Business Services/Public Information Officer	34 years
Albert E. Mouncer	Vice President, Corporate Services/General Counsel/Chief Financial Officer	25 years
Cheryl M. Whitcomb	Vice President, Organizational Performance and Staffing/Chief Knowledge Officer	31 years

EMPLOYEES

Energy Northwest currently employs approximately 1,069 employees. Of these employees, 298 are members of the International Brotherhood of Electrical Workers (“IBEW”), 125 are members of the United Steel Workers (“USW”) and 7 are members of the Hanford Atomic Metal Trades Council (“HAMTC”) unions. The IBEW union members comprise the Administrative, Nuclear, Travelers and Plant bargaining groups; the USW union members constitute the Security Force bargaining group; and the HAMTC union members comprise part of the Standards Lab Instrument Technicians. The Nuclear, Administrative, Travelers, Plant, IBEW and HAMTC collective bargaining agreements expire in 2007. The USW collective bargaining agreement expired on November 2, 2002. An arbitration hearing was held in December 2005 and the arbitrator’s decision resulted in a new three-year contract starting November 1, 2002, and expiring November 1, 2005. The new contract included a wage increase of 3.5% for the first year, and a 3.0% increase in both the second and third years. Negotiation has started on a new contract. A no-strike clause is included in each of the agreements.

INVESTMENT POLICY

Energy Northwest invests its funds in accordance with the authority provided by the Prior Lien Resolutions and the Electric Revenue Bond Resolutions, and its investment policy covers all funds and investment activities under the direct authority of Energy Northwest.

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

For further information on the types of investments in which Energy Northwest is permitted to invest its funds, see Appendix H-1 - "SUMMARY OF CERTAIN PROVISIONS OF ELECTRIC REVENUE BOND RESOLUTIONS AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS - Investment of Funds (Section 508)" and Appendix H-2 - "SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS - Other Funds Established by the Prior Lien Resolutions; Flow of Revenues."

THE COLUMBIA GENERATING STATION

Description

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 DOE's Hanford Reservation. The site has been leased from DOE for a term of 50 years commencing July 1, 1972, with options to extend the lease for two consecutive ten-year periods.

Columbia commenced commercial operation in 1984 and has a net design electric 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. Bonneville has acquired the entire capability of Columbia under the Columbia Net Billing Agreements. See "SECURITY FOR THE NET BILLED BONDS - NET BILLING AND RELATED AGREEMENTS."

Columbia consists of the following structures: the reactor building, the radioactive waste building, the turbine-generator building, the diesel generator building, the service building, six mechanical-draft evaporative cooling towers, the circulating water pumphouse and the river makeup water pumphouse. Makeup water to replace evaporative losses is obtained from the Columbia River by means of three makeup water pumps. Emergency power is supplied to Columbia by diesel generators sized to sustain all essential plant loads without the need for outside power sources. Columbia also includes the Independent Spent Fuel Storage Installation facility. For additional information concerning the Independent Spent Fuel Storage Installation facility, see "ENERGY NORTHWEST - THE COLUMBIA GENERATING STATION - Nuclear Fuel" below.

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

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

Management Discussion of Operations

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has a maintenance, operating, fuel and capital budget for Columbia of $202 million for the 2006 fiscal year, which ends on June 30, 2006.

The cost of production, using industry standard methodology (such cost calculation methodology includes general and administration and capital, but excludes debt service, taxes, depreciation and decommissioning costs) of Columbia electricity is budgeted at $20.85 per megawatt-hour for the 2006 fiscal year. This cost is lower than the $33.40 per megawatt-hour for the 2005 fiscal year because the 2005 fiscal year included a refueling outage as well as three forced outages. On July 30, 2004, the reactor shut down automatically from full power due to a computer control card component failure and subsequent closure of a main turbine governor valve. During the outage the card was replaced and several large valves were rebuilt. The refueling outage lasted 35 days and was the shortest in Columbia's history. Following the outage the plant was shut down for 11 days to fix problems with a feed water pump governor valve closure discovered immediately following the outage. The reactor has been continuously on line since restart on July 2, 2005. The next scheduled outage will be in May 2007. Energy Northwest continues to place a high priority on cost-containment.

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

To increase the value of the plant over time, engineers continue to work on a proposal to extend Columbia's 40-year operating license by 20 years, from 2023 to 2043. The NRC established a protocol to handle license extension requests and has granted 33 such requests since 2000. The Executive Board will determine when to apply for an extension.

Operating Performance

Columbia received a full operating license in March 1984, commenced commercial operation in December 1984 and has been in operation since that time. Since commencing commercial operation, Columbia has operated at a cumulative capacity factor of 69.1% and has generated 140,091,510 megawatt hours (net of station use) of electric power through December 2005.

Successful implementation of employee performance enhancement initiatives at Columbia has produced significant positive results in plant performance since 1995. Calendar year 2002 was the best generating calendar year at Columbia since commencing commercial operation, eclipsing the previous record in 2000. Fiscal year 2004 was the best generating fiscal year at Columbia since commencing commercial operation. In fiscal year 2004, Columbia produced 9,520 million kilowatt hours of electrical power while attaining a plant capacity factor of 97.9% and a plant availability factor of 99.4%.

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for fiscal years ended June 30, 2004 and 2005 and are shown below. The information is developed on a cost basis with depreciation calculated on the straight-line method by major components based on expected useful life.

Statement of Operations(1)
(Dollars in Thousands)

Cost Category	FY 2004	FY 2005
Operations, Maintenance and Overhead	$151,181	$197,296
Nuclear Fuel Burnup	35,322	28,570
Spent Fuel Disposal Fee	9,029	7,241
Generation Taxes	3,199	2,315
Decommissioning	42,993	5,397
Depreciation and Amortization	79,932	80,366
Investment Income	(1,878)	(4,160)
Interest Expense and Discount Amortization	119,604	116,306
Other Expense/(Revenue)	(1,967)	(2,761)
Total Costs	$437,415	$430,570
Net Generation (GWhs) (unaudited)	9,520(2)(3)	7,599(3)

(1) Amounts derived from audited Energy Northwest financial statements.
(2) Includes credit for "Economic Dispatch" of 16 GWhs for fiscal year 2004. Total energy not generated due to reductions requested by Bonneville is referred to by Bonneville as "Economic Dispatch."
(3) The decrease in generation was the result of three forced outages in 2005 in addition to the two-year refueling and maintenance outage in June 2005.

Capital Improvements

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. In fiscal year 2005, the cash spent on capital improvements was $24.4 million. These capital improvements included heightened security improvements mandated by the NRC that were substantially completed in 2005, upgrading the security system computer and certain improvements to reduce fatigue and extend continued operation for another 20 years. The majority of the proceeds of the Columbia 2006-C Bonds and Columbia 2006-D (Taxable) Bonds will be used to pay costs of certain capital improvements during fiscal years 2006 and 2007. See "PURPOSES OF ISSUANCE – New Money Bonds" for a description of the capital improvements planned for fiscal years 2006 and 2007.

Nuclear Regulatory Commission Actions

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

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

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

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

To monitor these seven cornerstones, the NRC assigned colors of Green, White, Yellow or Red to specific performance indicators and inspection findings. For performance indicators, a green coding indicates performance within an expected performance level in which the related cornerstone objectives are met; white coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; yellow coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin; and red coding indicates a significant reduction in safety margin in the area measured by that performance indicator. For inspection findings, green findings are indicative of issues that, while they may not be desirable, represent very low safety significance. White findings indicate issues that are of low to moderate significance. Yellow findings are issues that are of substantial safety significance. Red findings represent issues that are of high safety significance with a significant reduction in safety margin. In the Fourth Quarter of 2005, Columbia continued to be in the White region for the high pressure injection system unavailability performance indicator due to eleven days of maintenance in the first quarter of 2005 on the High Pressure Core Spray System pump motor following discovery of equipment issues. One other performance indicator crossed the Green/White threshold in the second quarter of 2005 but returned to Green in the third quarter. That was the unplanned scrams performance indicator. There have been no non-Green (White) findings in the last three years.

Results from the monitored cornerstones are compiled and published quarterly in the NRC's Reactor Oversight Process Action Matrix Summary. The Action Matrix Summary reflects overall plant performance, which is based on defined performance indicators and inspection findings. Individual plant performance is segregated into one of five performance columns.

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

The NRC's Third Quarter 2005 Regulatory Oversight Process Summary lists 80 plants in the Licensee Response Column, 17 plants, including Columbia, in the Regulatory Response Column and three plants in each of the next two lower columns. There are no plants currently included in the Unacceptable Performance Column.

Institute of Nuclear Power Operations

The nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. INPO's mission is to promote the highest levels of safety and reliability in the operation of nuclear electric generating plants. All United States utilities that operate commercial nuclear power plants are INPO members. INPO has conducted plant evaluations of Columbia approximately every 12 to 24 months since the initial date of commercial operation.

INPO performed an evaluation of Columbia in January 2005. A number of strengths and accomplishments were noted as well as areas for improvement. Based on the results of the plant evaluation, INPO defined Columbia's performance category as "overall performance is generally in keeping with the high standards required in nuclear power. However, improvements are needed in a number of areas. A few significant weaknesses may exist." Energy Northwest has established a team to administer an improvement template provided by INPO and evaluate the quality and adequacy of the corrective actions identified by the various departments within Energy Northwest. A number of the corrective actions will require capital costs to replace worn or aging equipment sooner than expected. These costs are included in the capital costs plan for Columbia.

Permits and Licenses

Energy Northwest has obtained all permits and licenses required to operate Columbia, including an NRC operating license which expires in 2023. See "— Nuclear Regulatory Commission Actions" above for a discussion of NRC activities related to Columbia.

A site certification agreement for Columbia was executed with the State of Washington in May 1972. The site certification requires Energy Northwest, among other things, to monitor the environmental effects of plant construction and plant operation, comply with standards set for the consumption and discharge of water and for discharges to the air, and develop an effective emergency plan. The state has also issued a National Pollutant Discharge Elimination System ("NPDES") permit and the necessary Certificate of Water Right. The Certificate of Water Right expires when use ceases. The NPDES permit is effective until April 2006 and is renewable for five-year terms thereafter. The renewal application has been filed and the current permit remains in effect until the new permit is issued. The Washington State Department of Natural Resources has entered into a lease with Energy Northwest for that portion of the bed of the Columbia River which encompasses the plant intake and discharge facilities. Energy Northwest anticipates renewal of this lease in accordance with the right-of-renewal provisions contained therein. The Corps has issued a permit for construction and maintenance of the completed river facilities. Energy Northwest has an interim status permit for storage of mixed radioactive and hazardous wastes. The processing of a final Resource Conservation and Recovery Act ("RCRA") permit has been suspended by the State of Washington pending a national review of mixed waste disposal capacity. Energy Northwest continues to manage its mixed wastes in accordance with the conditions of the interim status permit.

Nuclear Fuel

The supply of nuclear fuel assemblies requires four basic activities prior to insertion of the fuel assemblies into a nuclear reactor. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexaflouride, enrichment of the uranium hexaflouride and fabrication of the enriched uranium in the form of uranium oxide pellets into finished fuel assemblies.

The initial core of fuel assemblies was fabricated by General Electric and loaded into the reactor in December 1983. A portion of the fuel was then replaced during refueling outages so that by mid-1992 all of the initial core fuel had been replaced with reload fuel assemblies.

Since 2002 reload fuel design and fabrication services for three "firm" reloads has been provided pursuant to a contract with AREVA. Said contract also provides for two optional reloads.

Columbia had historically operated on a 12-month fuel cycle, but in 1998 a decision was made to transition to a 24-month fuel cycle. A 24-month fuel cycle eliminates refueling outages every other year and results in increased average generation. After two transition cycles totaling approximately 36 months in length, the first 24-month cycle began in 2001.

To meet the enriched uranium requirements for the reload fuel assemblies, Energy Northwest purchases uranium in various forms and holds them in inventory until needed for fuel fabrication. However, some or all of this inventory is being or might be loaned. Currently, Energy Northwest's inventory of natural uranium hexaflouride is sufficient for plant requirements through 2011.

Energy Northwest has a contract with DOE that requires the DOE to accept title and dispose of spent nuclear fuel. For this future service, Energy Northwest pays a quarterly fee based on about one mill per kilowatt-hour of net electricity generated and sold from Columbia ($7.2 million for the 12 months ended June 30, 2005). To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating a proposed site in Nevada for an underground geological repository. Although courts ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, the repository is not expected to be in operation before 2015. Once DOE begins to accept spent fuel, it will accept the oldest spent fuel first, on a national basis. Because Columbia is a relatively young plant, DOE does not plan to accept any spent fuel from Columbia during the first ten years of repository operation.

Columbia had sufficient capacity in the plant or at the plant site to accommodate all its spent fuel discharges through calendar year 2003. To accommodate spent fuel discharges after 2003, Energy Northwest constructed the Independent Spent Fuel Storage Installation ("ISFSI") facility, to store spent fuel in commercially available dry storage casks on concrete pads at the plant site. Energy Northwest has a contract for a dry storage cask system. The ISFSI facility will be expanded in increments as needed in the future. The ISFSI facility can be expanded to accommodate all spent fuel discharges through 2024 if necessary.

Decommissioning

The NRC has defined decommissioning as actions taken which result in the release of the property for unrestricted use and termination of the nuclear power plant operating license. Currently, the nuclear industry recognizes three alternative methods (decontamination, safe storage and entombment) to decommission a nuclear power plant. Energy Northwest's decommissioning plan is based on the safe storage method of decommissioning. Safe storage entails placing and maintaining the nuclear facility in a condition that allows it to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use. The NRC requires that this deferred decontamination period be no longer than 60 years.

Energy Northwest's current estimate of Columbia decommissioning costs is approximately $632 million (in 2005 dollars). This estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia. Additionally, site restoration requirements for Columbia are governed by the site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council. Energy Northwest's estimate of Columbia's site restoration costs is approximately $80 million (in 2005 dollars).

The current decommissioning funding plan requires annual deposits to a fund through fiscal year 2024, the estimated end of commercial operation of Columbia. The plan assumes that such deposits will grow at a 2% real rate of return and that Columbia will be placed in an approximately 60-year safe storage until 2085, at which time decontamination and dismantling will be completed. Over the life of the fund, deposits and the earnings related to the reinvestment thereof are expected to provide sufficient funds to cover the cash flow requirements to decommission Columbia. This plan will be re-examined every year and modified, if necessary, to assure that the projected fund balance complies with the then current estimates and NRC requirements. Payments to the decommissioning trust fund have been made since 1985, and the balance of cash and investment securities in the fund as of December 31, 2005, totaled approximately $97 million. A separate fund has been established for site restoration. The balance of this fund as of December 31, 2005, totaled approximately $12 million. These amounts are held in an external decommissioning trust fund in accordance with NRC requirements and are administered by Bonneville.

Insurance

Energy Northwest maintains a risk management and insurance program which incorporates a combination of self-insurance, commercial insurance and nuclear property and liability insurance. Energy Northwest's basic risk management philosophy is to pay normal and expected losses from revenues and to purchase insurance to cover catastrophic losses. Energy Northwest, as a licensee of the NRC, is subject to retrospective premiums for nuclear liability and property insurance on Columbia. Claims relating to Columbia, Project 1 or Project 3 that are not covered by insurance are paid from revenues under the related Project Net Billing Agreements.

Commercial liability insurance is purchased to cover all Energy Northwest premises and operations. This insurance provides coverage for injury or damage arising from non-nuclear accidents or occurrences. Energy Northwest maintains nuclear insurance in accordance with regulatory and Energy Northwest risk management policies.

Nuclear liability insurance covers third party injury or damage arising out of a nuclear incident and is required under the Price-Anderson Act, enacted in 1957 as an amendment to the Atomic Energy Act (as amended, "Price-Anderson"). Price-Anderson provides financial protection for the public in the event of bodily injury or property damage caused by a commercial nuclear incident.

In accordance with Price-Anderson, the nuclear liability exposures of Columbia are covered through the purchase of commercial nuclear liability insurance. This policy carries a limit of $300 million with no deductible and forms the primary layer of protection. The excess layer of protection above this amount is provided through a mandatory industry self-insurance program featuring an assessment provision to all licensed nuclear power reactors. This excess layer amount is just over $10.5 billion, based on 104 licensed reactors, multiplied by a current maximum retrospective assessment of $100.6 million per reactor, per any one nuclear incident. Therefore, the total public liability coverage available per incident is approximately $10.8 billion. It is important to note that in the event there is an incident triggering an assessment, the maximum annual deferred premium assessment would be $15 million per incident. This assessment is payable under the Columbia Net Billing Agreements.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by Energy Northwest and Bonneville. The total amount of insurance purchased is currently $2.75 billion. The deductible for this coverage is $5 million per occurrence. Additionally, Bonneville purchases business interruption coverage, which pays $3.5 million per week, following a 12 week deductible period for the first year and then for the next 110 weeks, pays 80% of this amount for a maximum indemnification of $490 million. The limits of liability and policy coverage for Columbia meet all legal requirements for a nuclear power production facility and are consistent with that purchased by other nuclear utilities relative to similar circumstances and exposures.

PACKWOOD LAKE HYDROELECTRIC PROJECT

Energy Northwest owns and operates Packwood, a hydroelectric generating facility with a net design electric rating of 27.5 megawatts. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles southeast of Seattle, Washington. Packwood was granted a FERC operating license on March 1, 1960, and began commercial operation in June 1964. The initial FERC license has a duration of 50 years and expires on February 28, 2010. Based on the existing FERC licensing process, Energy Northwest initiated relicensing efforts in fiscal year 2005.

Forty year average annual generation for the facility is 92,000 megawatt-hours. The electric power produced at the facility is expected to generate enough revenues to pay all Packwood costs, including debt service on the Packwood bonds. Until October 2002, the electric power produced at the facility was sold to Bonneville for distribution to the original 12 public utilities who are the Packwood participants. The Packwood participants are required to pay their share of the annual budget of the project, which includes debt service on the Packwood bonds, whether or not the project is producing power or capable of producing power. Since November 2002, the power produced is being sold directly to two of those participants, Benton County PUD and Franklin County PUD. The agreements with Benton County PUD and Franklin County PUD expire in September 2008.

NINE CANYON WIND PROJECT

Energy Northwest owns and operates Nine Canyon Wind Project, a wind energy project, capable of generating 64 megawatts of electricity. The project is located on leased land, near Kennewick, Washington, and includes 49 wind turbines.

Each turbine has a power generating capacity of 1,300 kilowatts. The turbines were manufactured by BONUS Energy A/S, a Denmark corporation. The project is a separate system of Energy Northwest and the bonds are secured by, and payable solely from, the revenues derived by Energy Northwest under power purchase agreements executed with public utility purchasers. The purchasers are required to pay their share of the annual budget of the project, which includes debt service on the related bonds, whether or not the project is operating or capable of operating. Power costs for the project billed to the purchasers have ranged from 3.5 cents per kilowatt hour to 3.6 cents per kilowatt hour during the first four fiscal years of operation (2001 through 2005).

PROJECT 1

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

Energy Northwest has been planning for the demolition of Project 1 and restoration of the site. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with asset sales and planning for the demolition and site restoration activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements. The agreement requires Bonneville to fund this site remediation plan for Projects 1 and 4 and the cost for both sites' remediation is estimated at $45 million in calendar year 2003 dollars. Bonneville has placed funds in an external interest-bearing account in order to have sufficient funds for the eventual final remediation.

PROJECT 3

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

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

PROJECTS 4 AND 5

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

ENERGY/BUSINESS SERVICES

More than a decade ago, Energy Northwest set out to develop new sources of electricity generation and provide energy and environmental related services to meet the needs of its member utilities and the region. Since 1992, Energy Northwest has provided a wide range of chemical analysis and environmental monitoring services to utility, municipal, commercial, and nuclear customers. Energy Northwest is a founding member of NoaNet, offering access to a fiber-optic cable network licensed from Bonneville and other broadband providers. Energy Northwest is actively investing in emerging technologies through its support of the Applied Process Engineering Laboratory, currently in its seventh year of operation. Energy Northwest has begun the search for biomass generating locations, adhering to its commitment to develop alternative power resources.

All of these current and future Energy Northwest initiatives to develop new sources of electricity generation and related energy and environmental services have been or will be funded from sources other than Bonneville or the Net Billing Agreements for Projects 1, 3 and Columbia.

On July 27, 2005, the Board of Energy Northwest approved the formation of a project for the purpose of eventually building an Integrated Gasification Combined Cycle power plant known as the Pacific Mountain Energy Center. The plant, if formally approved and built, is expected to begin operation in 2012.

NET BILLED PROJECTS LITIGATION AND CLAIMS

The following is a discussion of litigation and claims relating to the Net Billed Projects to which Energy Northwest is a party:

DuraBrake Company v. Energy Northwest. This is an action filed by Durametal Brake Company, LLC ("DuraBrake") versus Energy Northwest in Benton County Superior Court arising out of a landlord-tenant dispute relating to DuraBrake's leasing of an empty warehouse from Energy Northwest, which is located on the Project 1 site. This dispute relates to the leasehold agreement and commitments relating to the provision of upgraded electrical service to the warehouse. DuraBrake was a start-up business, attempting to develop a market in brake drum manufacturing. Following its inability to successfully conduct operations, DuraBrake filed a complaint for damages for breach of contract, tortious breach of contract, repudiation/breach of lease agreement, and retaliatory eviction in violation of public policy and tortious interference with business expectancy. DuraBrake engaged an expert who offered an opinion that DuraBrake had suffered damages in excess of $10 million. Energy Northwest in its answer to the claims brought by DuraBrake has denied the same. This matter is not currently set for trial and the outcome of the lawsuit cannot be predicted at this time.

Washington State Department of Revenue and General Electric. This is a contingent claim for taxes owed to the Washington State Department of Revenue for the period of 1995 through 2001. Energy Northwest has an agreement with General Electric that provides Energy Northwest the right to purchase services and goods from General Electric at a discount. The Washington State Department of Revenue has completed two separate audits of General Electric covering 1995 through 2001. The Department of Revenue has assessed sales tax and business and occupation tax on sales made by General Electric to Energy Northwest under its agreement. The issue is whether the taxes are owed on the full price of the goods or service or on the discounted price. The Department of Revenue has asserted that the "discount" is a cash item and that sales tax is due on the gross sales price. The assessment against General Electric is in the aggregate amount of $5,612,447. Contract language in the Energy Northwest and General Electric agreement requires Energy Northwest to indemnify General Electric for additional tax liability arising out of the discount program. Energy Northwest contests the Department of Revenue's assertions and expects to assert defenses that mitigate both the amount and likelihood of an adverse judgment in this matter. The outcome of this matter cannot be predicted at this time.

Energy Northwest v. United States of America. This is an action filed by Energy Northwest against the United States of America (the "Government") in the U.S. Court of Federal Claims in January 2004 for breach of contract and breach of implied covenant of good faith and fair dealing. On June 13, 1983, Energy Northwest entered into a written contract with the United States for disposal of spent nuclear fuel ("SNF") and high-level radioactive waste. The Government, in its contract, agreed to accept and dispose of the SNF beginning not later than January 31, 1998. The Government failed to meet its obligation and declared that it will not begin to dispose of SNF until 2010 at the earliest. Energy Northwest seeks recovery of damages for, among other things, substantial costs resulting from the Government's breach of contract, including but not limited to (1) the costs to investigate, design, license, and construct alternative storage facilities and to purchase and load casks to store SNF at those facilities; and (2) the operations, maintenance, and security costs Energy Northwest will incur to store SNF at Columbia beyond the time that the Government would have removed all the SNF had it not breached the Standard Contract. On May 12, 2004, the Court ordered that discovery on the issues of rate of acceptance and damages be stayed. The Government filed its answer to Energy Northwest's complaint on August 6, 2004. On June 17, 2005, the Government filed a summary judgment motion, seeking to dismiss Energy Northwest's lawsuit on the basis that Energy Northwest is not entitled to damages. On August 11, 2005, Energy Northwest filed its response to the Government's motion. On January 30, 2006, the U.S. Court of Federal Claims denied the Government's motion for summary judgment and ruled that the Government breached its contract with Energy Northwest as of January 31, 1998, when it failed to begin accepting SNF from the nuclear utility industry on that date. The quantum of Energy Northwest's damages will be addressed in further proceedings, which have not been scheduled at this time. The extent of the damages award cannot be predicted at this time.

McManman v. Energy Northwest. In this action, the plaintiff alleged that Energy Northwest violated the Washington State Open Public Records Act. Mr. McManman, individually, and doing business as the Eastside Business Post, requested a copy of the 2005 Institute of Nuclear Power Operations ("INPO") Final Report. When his initial request was denied, indicating that the INPO report was "proprietary information," Mr. McManman appealed to the Energy Northwest Executive Board and was informed that INPO copyrights the report and prohibits the distribution of its contents to any third party or that it be made public without their written consent. INPO intervened in this action. A hearing on Summary Judgment was held on January 27, 2006. The outcome of the lawsuit cannot be predicted at this time.

LEGAL MATTERS

The approving opinions of Preston Gates & Ellis LLP, Bond Counsel to Energy Northwest, as to the legality of the 2006 Bonds will be in substantially the form appended hereto in Appendix D-1 - "PROPOSED FORM OF OPINIONS OF BOND COUNSEL." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the exclusion of the interest on the Series 2006-A Bonds from the gross income of the owners thereof for federal income tax purposes will be in substantially the form appended hereto in Appendix E - "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL."

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

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

Certain legal matters, including the enforceability against Bonneville of the Net Billing Agreements and the Assignment Agreements relating to Project 1, Columbia and Project 3, will be passed upon for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., New York, New York, Counsel to the Underwriters.

TAX MATTERS

SERIES 2006-A BONDS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2006-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"),. Special Tax Counsel is of the further opinion that interest on the Series 2006-A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Special Tax Counsel observes that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. In rendering its opinion, Special Tax Counsel has relied on the opinion of Bond Counsel as to the validity of the Series 2006-A Bonds and the due authorization and issuance of these Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E - "PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL."

To the extent the issue price of any maturity of the Series 2006-A Bonds is less than the amount to be paid at maturity of such Series 2006-A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2006-A Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the Series 2006-A Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Series 2006-A Bonds is the first price at which a substantial amount of such maturity of the Series 2006-A Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the Series 2006-A Bonds accrues daily over the term to maturity of such Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such Series 2006-A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2006-A Bonds. Beneficial Owners of the Series 2006-A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2006-A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2006-A Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2006-A Bonds is sold to the public.

Series 2006-A Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a purchaser's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such purchaser. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

Title XIII of the 1986 Act and the 1954 Code impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series 2006-A Bonds. Energy Northwest and Bonneville have made certain representations and have covenanted to comply with certain restrictions designed to ensure that interest on the Series 2006-A Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2006-A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of these Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring) after the date of issuance of the Series 2006-A Bonds may adversely affect the value of, or the tax status of, interest on these Bonds.

Certain agreements, requirements and procedures contained or referred to in the Net Billed Resolutions, as applicable, the Tax Matters Certificates to be executed and delivered by Energy Northwest and by Bonneville simultaneously with the issuance of the Series 2006-A Bonds, and other relevant documents may be changed and certain actions (including without limitation defeasance of the 2006-A Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. Special Tax Counsel expresses no opinion as to any Series 2006-A Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice or approval of counsel other than Orrick, Herrington & Sutcliffe LLP.

Although Special Tax Counsel is of the opinion that interest on the Series 2006-A Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of interest on, these Bonds may otherwise affect a Beneficial Owner's federal or state tax liability. The nature and extent of these other tax consequences will depend upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Special Tax Counsel expresses no opinion regarding any such other tax consequences.

The opinion of Special Tax Counsel is based on current legal authority and represents Special Tax Counsel's judgment as to the proper treatment of the Series 2006-A Bonds for federal income tax purposes. It is not binding on the IRS or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of Energy Northwest or Bonneville, or about the effect of future changes in the 1986 Act, the 1954 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville have covenanted, however, to comply with applicable requirements of the 1986 Act or the 1954 Code.

Future legislation, if enacted into law, or clarification of the 1954 Code or the 1986 Act may cause interest on the Series 2006-A Bonds to be subject, directly or indirectly, to federal income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislation or clarification of the 1954 Code or the 1986 Act may also affect the market price for, or marketability of, the Series 2006-A Bonds. Prospective purchasers of these Bonds should consult their own tax advisors regarding any pending or proposed federal tax legislation, as to which Special Tax Counsel expresses no opinion.

Special Tax Counsel's engagement with respect to the Series 2006-A Bonds ends with the issuance of the Series 2006-A Bonds, and, unless separately engaged, Special Tax Counsel is not obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2006-A Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than Energy Northwest, Bonneville and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which Energy Northwest or Bonneville legitimately disagrees may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2006-A Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2006-A Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

SERIES 2006-B (TAXABLE) BONDS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, interest on the Series 2006-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the Internal Revenue Code of 1986. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2006-B (Taxable) Bonds.

CIRCULAR 230 DISCLAIMER

Investors are urged to obtain independent tax advice regarding the Series 2006-B (Taxable) Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2006-B (Taxable) Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2006-B (Taxable) Bonds.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") and Fitch, Inc. ("Fitch") have assigned the 2006 Bonds the ratings of Aaa, AA- and AA-, respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the 2006 Bonds. Such ratings reflect only the respective views of such rating agencies, and an explanation of the significance of such ratings may be obtained only from the rating agency furnishing the same. There is no assurance that any or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the 2006 Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2006 Bonds from Energy Northwest and to make a bona fide public offering of such Bonds at not in excess of the public offering prices set forth on the inside cover of this Official Statement. Aggregate underwriters' compensation under the bond purchase contract for the Series 2006-A Bonds and Series 2006-B (Taxable) Bonds is $3,900,295. The Underwriters' obligations are subject to certain conditions precedent contained in the bond purchase contract and they will be obligated to purchase all of such 2006 Bonds if any such 2006 Bonds are purchased. The 2006 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2006 Bonds into investment trusts) at prices lower than such initial offering prices and such initial offering prices may be changed from time to time by the Underwriters of the 2006 Bonds.

CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934 ("Rule 15c2-12"), Energy Northwest and Bonneville will enter into Continuing Disclosure Agreements, to be dated the date of delivery of the 2006 Bonds, for the benefit of the owners and beneficial owners of the 2006 Bonds, to provide certain financial information and operating data relating to Energy Northwest (the "Energy Northwest Annual Information"), certain financial information and operating data relating to Bonneville (the "Bonneville Annual Information" and, together with Energy Northwest Annual Information, the "Annual Information") and to provide notices of the occurrence of certain enumerated events with respect to the 2006 Bonds, if material. Energy Northwest Annual Information is to be provided not later than December 31 of each year, commencing December 31, 2006. The Bonneville Annual Information is to be provided not later than March 31 of each year, commencing March 31, 2007. The Annual Information will be filed with each Nationally Recognized Municipal Securities Information Repository (the "NRMSIRs") (or provided to a transmitting entity approved by the SEC) and with the State Depository for the State of Washington, if such State Depository exists (the "State Depository"). At this time, there is no State Depository for the State of Washington. Notices of aforesaid enumerated events will be filed by Energy Northwest with the NRMSIRs or the Municipal Securities Rulemaking Board (the "MSRB") and with the State Depository. Energy Northwest and Bonneville have complied with all previous undertakings with respect to Rule 15c2-12. The nature of the information to be provided in the Annual Information and the notices of such material events is set forth in Appendix J - "SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS."

INITIATIVE AND REFERENDUM

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

MISCELLANEOUS

The references, excerpts and summaries contained herein of the Prior Lien Resolutions, Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements, the Post Termination Agreements and any other documents or agreements referred to herein do not purport to be complete statements of the provisions of such documents or agreements, and reference should be made to such documents or agreements for a full and complete statement of all matters relating to the 2006 Bonds, the basic agreements securing the 2006 Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Prior Lien Resolutions, Electric Revenue Bond Resolutions, Net Billing Agreements, the Columbia Project Agreement, Assignment Agreements and the Post Termination Agreements and other reports, documents, agreements and studies referred to herein and in the Appendices hereto are available upon request at the office of Energy Northwest in Richland, Washington.

The authorizations, agreements and covenants of Energy Northwest are set forth in the Prior Lien Resolutions and Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the 2006 Bonds is to be construed as a contract with the holders of such Series of 2006 Bonds. Any statements made in this Official Statement involving matters of opinion or estimates, whether or not expressly so identified, are intended merely as such and not as representations of fact.

Bonneville has furnished the information herein relating to it.

ENERGY NORTHWEST

By: /s/ Edward E. Coates
Chairman, Executive Board

By: /s/ Richard A. Bresnahan
Authorized Officer

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest ("Energy Northwest" or, the "Issuer") by Bonneville for use in the Official Statement, dated March 23, 2006, furnished by the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2006-A, Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-A, Project 3 Electric Revenue Refunding Bonds, Series 2006-A, Project 1 Electric Revenue Refunding Bonds, Series 2006-B (Taxable), Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-B (Taxable) and Project 3 Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (collectively, the "Series 2006 Bonds"). (Project 1, Project 3 and the Columbia Generating Station are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as the "Net Billed Projects.") Such information is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2006 Bonds, Bonneville will certify to the Issuer that the information in this Appendix A, as well as information pertaining to Bonneville contained elsewhere in the Official Statement, 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 Appendix A and in the 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 U.S. Department of Energy ("DOE"). Many of Bonneville's statutory authorities are vested in the Secretary of Energy, who appoints, and acts by and through, the Bonneville Power Administrator. Some other authorities are vested directly in the Bonneville Power Administrator.

Bonneville's primary enabling legislation includes the following Federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 Federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-Federally-owned and -operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by Energy Northwest and having a rated capacity of approximately 1150 megawatts. Bonneville estimates that the foregoing projects have an expected aggregate output of roughly 10,200-10,400 annual average megawatts under median water conditions and about 7800-8000 annual average megawatts under low water conditions.

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 three-fourths 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 region of the United States, encompassing the entirety of the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the 300,000 square-mile service area is approximately eleven million people. Electric power sold by Bonneville accounts for about 40 percent of the electric power consumed within the Region. Bonneville markets a large portion of this power to over 100 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service Bonneville provides to DSIs has diminished substantially relative to levels from the 1940s through the 1990s. Bonneville is also required by law to exchange power with qualifying utilities to meet their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," may result in payments by Bonneville to the exchanging utilities if the applicable power rates for Federal Columbia River Power System ("Federal System") power are lower than the utilities' respective average system cost of meeting their residential and small farm power loads. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs").

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. While Bonneville is a single legal entity, it 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 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 Reclamation for certain costs allocated to power generation at Federally-owned hydroelectric projects in the Pacific Northwest; and, (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its payment responsibility to the United States Treasury of $1.088 billion (including $313 million in principal payments in advance of due dates under the Debt Optimization Program as described in this Appendix A) in full and on time for the fiscal year ended September 30, 2005 ("Fiscal Year 2005"). Bonneville has made all payments to the United States Treasury in full and on time since 1984. For more information, see "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Debt Optimization Program."

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 deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the proposed Direct Pay Agreements, and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. For a description of the Net Billing Agreements, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS." For a description of the 1989 Letter Agreement, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS—General." For a description of the proposed Direct Pay Agreements, see the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Proposed Direct Pay Agreements" and see, in this Appendix A, "BONNEVILLE FINANCIAL OPERATIONS—Proposed Direct Pay Agreements." In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments if any under Net Billing Agreements, cash payments, if any, under the 1989 Letter Agreement and cash payments if any under the proposed Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS."

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.

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 levels but declined in fiscal year 2002. Prices have risen in subsequent fiscal years. 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.

In view of developments in past years, Bonneville believes that its revenues and expenses are, and will be, subject to several key risks: (i) the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from discretionary sales of energy and the cost of necessary power purchases Bonneville may have to make to meet contracted loads; (ii) the level of Bonneville's load serving obligation; (iii) water conditions in the Columbia River basin, which determine the amount of hydroelectric power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (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 power from the Federal System; and (v) operating costs, generally.

Power Loads and Related Contracts and Power Rates for the Fiscal Years 2002 through 2011

Subscription Agreements in Fiscal Years 2002 through 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, Federal agencies and DSIs, and all of Bonneville's settlements with Regional IOUs to whom Bonneville is required by law to provide Residential Exchange Program benefits, expired. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program." In anticipation of the expiration of such contracts and during the unprecedented volatility in Western power markets in fiscal years 2000 and 2001, Bonneville and its Regional customers negotiated 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 certain "Subscription Agreements" comprised of power sales contracts with 127 Regional Preference Customers, eight Federal agencies, and a small number of DSIs, and settlement contracts with all six of the Regional IOUs to settle Bonneville's obligations under the Residential Exchange Program. The foregoing contracts expire at or near the end of fiscal year 2011, except for the DSI contracts which, to the extent not yet terminated, expire at the end of fiscal year 2006.

The aggregate power sales commitment initially undertaken by Bonneville under these agreements, together with certain pre-existing surplus firm power sales and related obligations, substantially exceeded the aggregate amount of power from Federal System generating resources. To meet a portion of the difference, Bonneville entered into about 1000 average megawatts of short-term (less than five year) power purchases to augment Federal System generation resources (Augmentation Agreement purchases) and a number of load reduction agreements with its Regional customers under which agreements Bonneville agreed to pay customers to reduce the amount of power Bonneville otherwise was obligated to provide under related Subscription Agreements. As a result of the Augmentation Agreement purchases and load reduction agreements, Bonneville has been able to assure that its loads in the five years beginning September 30, 2002 have not exceeded its generation resources and contract purchases on a planning basis, although the actions created available surplus power that Bonneville has marketed. In particular, Bonneville's Subscription Agreement sales to DSIs and Regional IOUs have declined substantially from the amounts originally contracted to in the original Subscription Agreements. In addition, the amounts sold to DSIs have declined from levels in the years immediately preceding fiscal year 2002. Conversely, Bonneville's requirements sales to Preference Customers under Subscription Agreements increased when compared to such sales in the years immediately preceding fiscal year 2002.

Subscription and Related Power Rates for Fiscal Years 2002 through 2006

Coincident with the development of the power sales and related contracts under the Subscription Strategy, Bonneville proposed power rates for such Subscription Agreements for the five-year period ending September 30, 2006 (the "2002 Final Power Rates"). The 2002 Final Power Rates provide, among other things, rates used for Subscription Agreement power sales to Preference Customers (which comprise a substantial portion of all Subscription Agreement power sales), to Federal agency customers and DSIs, and in connection with the Residential Exchange Program. With regard to Subscription Agreement sales to Preference Customers, Bonneville provides four basic types of service to meet such customers' electric power requirements: (i) full requirements service in which Bonneville meets all of the loads of a related customer, (ii) partial requirements service in which Bonneville meets the loads of a related customer after taking into account the customer's own generating or contract resources, (iii) Block sales in which Bonneville sells fixed amounts of power under defined schedules, which power the customer applies to meet its loads, and (iv) Slice of the System in which a customer receives a proportionate share of the output of the Federal System as generated, which share the customer commits to meeting its loads.

The 2002 Final Power Rates are comprised of "base rates" and three separate rate level adjustments that have provided for periodically adjusted variable power rates in connection with Subscription Agreements. Under the first year of the foregoing five year rate structure (the "2002-2006 Rate Period"), Bonneville's rate levels increased substantially from the prior fiscal year's levels. For example, rate levels for full requirements service to Preference Customers (with certain limited exceptions) increased roughly 50 percent, from about $21 per megawatt hour in fiscal year 2001 to about $32 per megawatt hour in fiscal year 2002. The increase occurred primarily because one of the rate level adjustments began recovering an increment of revenue necessary to cover the direct cost of load reduction agreements and the cost of the then newly incurred Augmentation Agreement purchases. As a result of the operation of one or more of the rate level adjustments, in fiscal years 2003 and 2004, average annual power rate levels for Subscription Agreement sales were comparable to or slightly higher than the rate levels in fiscal year 2002. Such rate levels declined somewhat in fiscal years 2005 and 2006. For a more detailed description of Bonneville power rates and rate levels for the five year rate period ending September 30, 2006, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Subscription Power Rates for Fiscal Years 2002 through 2006."

FERC has approved the 2002 Final Power Rates and related provisions that Bonneville developed in fiscal year 2004 to implement one of the rate level adjustments. The foregoing rates and implementing provisions are the subject of legal challenges in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court"), which has direct review jurisdiction over statutory, rates and many administrative law legal challenges to Bonneville actions. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge," and "BONNEVILLE LITIGATION—Fiscal Year 2004 SN-CRAC Adjustment Litigation."

Subscription and Related Agreements in Fiscal Years 2007 through 2011

To address Bonneville's role in meeting Regional electric power loads for the period after September 30, 2006, in early 2002 Bonneville began a discussion with customers and other interested parties in the Region (the "Regional Dialogue"). The Regional Dialogue was divided into two phases, with the initial phase focusing on the five years beginning October 1, 2006. The culmination of this phase was Bonneville's issuance in February 2005 of its Policy for Power Supply Role for Fiscal Years 2007-2011 – Administrator's Record of Decision ("Power Supply ROD"). One of Bonneville's core principles from the beginning of the Regional Dialogue discussions was to limit the total sales commitment Bonneville would undertake at its lowest-cost rate. Bonneville stated that it would prefer to achieve this objective by limiting the incremental load obligations Bonneville would bear above existing Federal System generating resources. As a means of balancing its statutory obligation to meet electric power loads placed on it by Preference and Regional IOU customers and its historical power sales relationship with DSI customers, with the goal of low, stable power rates, Bonneville indicated in its Regional Dialogue proposals that (i) it would prefer to have customers in the Region assume the role of meeting their own incremental load growth, and (ii) the incremental cost incurred by Bonneville to meet such loads, if any, would be recovered under a separate rate increment reflective of such, presumably higher, costs.

In view of the ongoing Regional Dialogue and other developments in the past several years, Bonneville's load commitments for fiscal years 2007 through 2011 have become more clearly defined.

All of Bonneville's Preference Customers have signed power sales contracts through fiscal year 2011, reflecting original Subscription Agreements and the recent extension for an additional five years of about 800 average megawatts in Preference Customer requirements power sales that were originally set to expire at the end of fiscal year 2006. Bonneville proposes no other increases in Subscription Agreement power sales to Preference Customers, apart from certain limited commitments to meet load growth through fiscal year 2011. Bonneville now expects that its Preference Customer loads will range between 7150 and 7450 annual average megawatts in fiscal years 2007 through 2011.

With respect to service to the aluminum company DSIs, Bonneville expects to offer new five-year contracts under which Bonneville would provide limited, monetized power benefits to qualifying DSIs in fiscal years 2007 through 2011. Bonneville has proposed to reserve the right to meet this amount by means of physical power sales in fiscal years 2010 and 2011. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—DSI Loads."

With respect to the six Regional IOUs, Bonneville has contractual assurances that it will not have to meet any of the Regional IOUs' loads in fiscal years 2007 through 2011, although Bonneville remains contractually obligated to provide substantial payments to Regional IOUs under Residential Exchange Settlement Agreements. Furthermore, in view of the fact that certain customers have filed legal challenges to the Residential Exchange Settlement Agreements and related actions, Bonneville has indicated that in the event a court were to set aside the Residential Exchange Settlement Agreements, Bonneville would nevertheless provide financial benefits, not power benefits, in fiscal years 2007 through 2011, unless otherwise prohibited by court order. If Bonneville were to enter into physical power sales obligations to Regional IOUs to effect the Residential Exchange Settlement Agreements without corresponding reductions in power sales to Preference Customers, Bonneville could have generating resource deficits. This could increase the amount of power purchases that Bonneville would have to make, perhaps substantially. For information about the Residential Exchange Program, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Residential Exchange Program Obligations," "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program," and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Other developments that have affected Bonneville's load resource balance forecasts are the expiration, termination and expected expiration of about 1000 average megawatts of Augmentation Agreement purchases prior to or shortly after the end of fiscal year 2006. A number of long term surplus power sales have expired or will expire as well.

As a result of the foregoing and other developments Bonneville now anticipates that its aggregate available firm generating resources and its loads will be roughly in balance in fiscal years 2007-2011, with a small surplus in the early years and relatively small deficits in the later years. Bonneville believes that it will not have to acquire substantial net amounts of electric power to meet annual energy loads during that period. Bonneville expects that in aggregate its loads will be about 8260 annual average megawatts in fiscal year 2007, rising to between 8350 and 8450 annual megawatts in fiscal year 2011. Of these projected loads, Subscription Agreement loads will be about 7150 annual average megawatts in fiscal year 2007, rising to between 7350 and 7450 annual average megawatts in fiscal year 2011. Other Bonneville power contract obligations are forecasted to be about 1030 annual average megawatts in fiscal year 2007, decreasing to about 1000 annual average megawatts by fiscal year 2011. Bonneville expects that under low water conditions, the Federal System (including power from certain contracts for transfers and exchanges, and taking into account power lost through transmission) will be able to meet annual loads of between 8260 and 8350 annual average megawatts in fiscal year 2007 declining to between 8175 and 8330 annual average megawatts in fiscal year 2011.

2007 Wholesale Power Rate Proceeding and Initial 2007 Power Rate Proposal

Bonneville has initiated the formal process for setting wholesale power rates to replace the 2002 Final Power Rates, which expire on September 30, 2006. In November 2005, Bonneville published an initial power rate proposal ("2007 Initial Rate Proposal") to cover the three fiscal years beginning October 1, 2006 ("2007 Rate Period"). Bonneville has commenced a formal administrative process that will lead to the preparation and publication by Bonneville of a draft record of decision, which is expected to be released near the end of May 2006. Bonneville expects to issue a final record of decision ("Final ROD") in early July 2006 and submit the Final ROD and a final proposed set of rate schedules (collectively, the "2007 Final Power Rate Proposal") to FERC by August 1, 2006 for its review. Bonneville expects that FERC will grant an order prior to October 1, 2006 approving the 2007 Final Power Rate Proposal on a provisional basis pending final review. Final FERC review of Bonneville's proposed power rates may take a year or more from the date of submission.

Because such a large part of Bonneville's power sales in the 2007 Rate Period will be made to Preference Customers under Subscription Agreement sales, the key elements of the 2007 Initial Rate Proposal relate primarily to Bonneville's rates for wholesale power service to Preference Customers for their requirements under Block sales, Slice of the System, and full and partial requirements service contracts. Bonneville will also propose rates for sales to DSIs and to determine the exchange rate applicable under the Residential Exchange Program, although Bonneville does not expect to have any transactions to which such rates would apply.

The rate proposal is built around a cumulative probability of full and timely payment to the United States Treasury of 92.6 percent for the three-year rate period (equivalent to a 97.5% annual probability of payment in each of the three years). To address various risks, the 2007 Initial Rate Proposal relies on (i) "base rates" for Subscription Agreement power sales that would be set at levels Bonneville believes to be sufficient to yield a reasonably high probability of modified net revenues (described below in "—Bonneville's Fiscal Year 2005 Financial Results," and (ii) a rate level adjustment mechanism (similar to one of the three rate level adjustment mechanisms implemented in the 2002 Final Power Rates) that would allow rate levels to fluctuate from year to year according to costs and revenues.

Under the 2007 Initial Rate Proposal, Bonneville has proposed wholesale power rates for the 2007 Rate Period which would provide base rates for Subscription Agreement power sales comparable to rate levels in effect in fiscal year 2006. For example, under the 2007 Initial Rate Proposal Bonneville would charge about $30 per megawatt hour for its core power service: full requirements service to Preference Customers. By contrast, Bonneville's rate levels in the current fiscal year for similar service are about $29 per megawatt hour.

The 2007 Initial Rate Proposal was prepared prior to the issuance of the President's Budget for Fiscal Year 2007, which proposes that Bonneville, under certain conditions, pay down the aggregate amount of outstanding bonds issued by Bonneville to the United States Treasury ("2007 Budget Proposal"). See "—President's Fiscal Year 2007 Budget." Bonneville does not expect that the 2007 Budget Proposal would affect the substance or timing of the 2007 Final Power Rate Proposal, but Bonneville is planning to initiate in the summer of 2006 an additional formal rate process to implement the 2007 Budget Proposal. While the rate level impacts of the 2007 Budget Proposal during the 2007 Rate Period are difficult to estimate by Bonneville, Bonneville's preliminary analysis indicates that implementation of the proposal would not affect power rate levels in fiscal year 2007 but, on a probabilistic basis, would increase power rate levels in the last two years of 2007 Rate Period over what the final proposed rate levels would otherwise be. See "—Fiscal Year 2006 Developments—President's Fiscal Year 2007 Budget" and "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Proposed Power Rates for Fiscal Years 2007 through 2011" and "—The Effect of the President's 2007 Budget Proposal on Proposed Power Rates."

Power Sales in the Period after Fiscal Year 2011

All of Bonneville's Subscription Agreements with Regional Preference Customers, all of the Residential Exchange Settlement Agreements and all of the proposed DSI power sales contracts will expire at the end of fiscal year 2011. In May 2005, Bonneville commenced the second-phase of the Regional Dialogue, which seeks to address, as the basis for new 20-year power sales and related contracts, how Bonneville would implement the policy direction limiting its power sales at the lowest cost-based rates to roughly the output of existing Federal System generating resources.

In September 2005, Bonneville issued a "Long-Term Regional Dialogue Concept Paper." The Concept Paper described Bonneville's proposals on all key post-2011 issues as a starting point for a series of work sessions with customers and other interested parties. Among the key elements of Bonneville's proposal for service to Preference Customers after fiscal year 2011 are the execution of new 20-year power sales contracts for the period beginning with fiscal year 2012, and the establishment of the basic features of a long-term rate methodology. Bonneville's identified rate methodology would restrict the power that Preference Customers may purchase under Bonneville's lowest-cost rate to an amount equal to the generating output of the existing Federal System. Any incremental purchases by such customers from Bonneville above the base amount of power would be sold at a higher rate reflecting the incremental cost to Bonneville of obtaining power to meet the incremental loads. To implement this construct, Bonneville has proposed to establish for each existing Preference Customer a contractually defined level of access to power service from the existing Federal System, based (with some exceptions) on each customer's fiscal year 2002 purchases under its related Subscription agreement. This would constitute each customer's "Tier 1" allocation. Any net requirements load placed on Bonneville by a customer in excess of its Tier 1 allocation would be sold at rates that recover the marginal cost to Bonneville of acquiring the resources needed to serve such loads.

With respect to the Residential Exchange Program, Bonneville's preferred alternative is to enter into settlement agreements with Regional IOUs that would provide them with between $100 million and $300 million annually in aggregate Residential Exchange Program benefit payments, as is provided for in the five fiscal years beginning with fiscal year 2007 under the Residential Exchange Settlement Agreements. Absent a settlement for the period after fiscal year 2011, Bonneville would initiate necessary administrative and public processes to implement the Residential Exchange Program as specified in the Northwest Power Act. The related provisions of the Act provide for detailed administrative and rates processes and complex substantive guidance to establish the cost methodologies and rates applicable to the Residential Exchange Program.

Bonneville expects to publish a formal post-2011 policy proposal in the Federal Register near the end of March 2006 and to issue a final policy and record of decision in late spring 2006.

Bonneville's Fiscal Year 2005 Financial Results

As set forth in Bonneville's audited financial statements for Fiscal Year 2005, Bonneville made payments to the United States Treasury of $1.088 billion in fiscal year 2005. These payments were made in accordance with Bonneville's scheduled United States Treasury repayment responsibilities and also included $313 million in advance amortization of debt under the Debt Optimization Program. See "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Program." Bonneville also recorded modified net revenues of approximately $126 million. Modified net revenues are net revenues from operations less (i) the effects of the Debt Optimization Program and other debt management actions relating to Energy Northwest, and (ii) unrealized mark-to-market gains under the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard No. 133 ("SFAS 133"). Bonneville believes that under current circumstances, modified net revenues are a better reflection of Bonneville's financial results than standard accounting determinations of net revenues. For a description of SFAS 133, see footnote 5 to the table "Federal System Statement of Revenues and Expenses" under "BONNEVILLE FINANCIAL OPERATIONS."

In fiscal year 2004, Bonneville made payments to the United States Treasury in the amount of $1.053 billion. This amount included $346 million in advance amortization of debt under the Debt Optimization Program. In fiscal year 2004, Bonneville recorded modified net revenues of about $66 million, reflecting net revenues of $504 million less $349 million in nonfederal debt management actions and $89 million in unrealized mark-to-market gains under SFAS 133.

A number of elements affected Bonneville's financial performance in Fiscal Year 2005. Bonneville recorded an increase in modified net revenues from $66 million to $126 million despite some negative influences on 2005 revenues. First, run-off conditions in Operating Year 2005 (August 1, 2004 to July 31, 2005) were about 81 percent of the 71-year average, representing the sixth consecutive year of below average runoff conditions in the Region. Second, average power rates for Subscription Agreement power sales declined somewhat from the prior fiscal year after taking into account the aggregate effect of the three rate level adjustment mechanisms in Bonneville's 2002 Final Power Rates. For a description of the three rate level adjustment mechanisms Bonneville established in the 2002 Final Power Rates, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Subscription Power Rates for Fiscal Years 2002 through 2006." Third, in Fiscal Year 2005, Bonneville received a total of about $58 million of United States Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act, a decrease from the prior year. These credits ("4(h)(10)(C) credits") are provided to reimburse Bonneville for certain fish and wildlife costs incurred by Bonneville, including power purchases made by Bonneville, that are attributable to the effects of operating the Federal System dams for the benefit of fish. 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." The largest contributing factor to the improvement in modified net revenues was an increase in revenues from discretionary power sales of hydroelectric generation. The increase in discretionary power sales reflect somewhat better runoff conditions than in fiscal year 2004 when runoff was about 77 percent of average, and better prices for discretionary power sales.

In addition, Bonneville closed Fiscal Year 2005 with $554 million in fiscal year-end cash balances as compared to $638 million at the end of fiscal year 2004 and $511 million at the end of fiscal year 2003. Bonneville's cash balances 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."

Energy Policy Act of 2005

The Energy Policy Act of 2005 ("EPA-2005") was enacted by Congress in July 2005. Among other things, EPA-2005 amended the Federal Power Act ("FPA") by including new provisions applicable to Bonneville's power and transmission marketing. Provisions in EPA-2005 that could have the greatest impact on Bonneville's operations include the following:

(i) EPA-2005 amends the FPA to authorize FERC to require an "unregulated transmitting utility" (a term that includes Bonneville) to provide transmission services at rates comparable to those the utility charges itself, and on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. Although Bonneville is uncertain how FERC will apply its new authority (for instance, the reporting or filing requirements FERC might impose or how FERC might interpret the provision), since 1996 Bonneville has voluntarily adopted terms and conditions for non-discriminatory open access transmission services through a FERC-filed tariff, offering transmission service to Bonneville's Power Business Line and other transmission users at the same tariff terms and conditions, and at the same rates. See "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of Business Lines."

(ii) With respect to Bonneville's participation in a regional transmission organization, EPA-2005 authorizes the Secretary of Energy or, upon designation by the Secretary, the administrator of a power marketing administration ("PMA") including Bonneville, to transfer control and use of the PMA's transmission system to certain defined entities, including a regional transmission organization, independent system operator, or any other transmission organization approved by FERC for operation of transmission facilities. The section further provides that the contract, agreement, or arrangement by which control and use is transferred must include provisions that ensure recovery of all of the costs and expenses of the PMA related to the transmission facilities subject to the transfer, consistency with existing contracts and third-party financing arrangements, and consistency with the statutory authorities, obligations, and limitations of the PMA. See "TRANSMISSION BUSINESS LINE—Bonneville's Participation in a Regional Transmission Organization."

(iii) EPA-2005 grants FERC limited authority to order refunds in the case of certain energy sales by non-jurisdictional utilities such as Bonneville. The refund authority is limited to sales of 31 days or less made through an organized market in which the rates for the sale are established by a FERC-approved tariff. The refund authority applies to Bonneville only if the rate for the sale by Bonneville is unjust and unreasonable and is higher than the highest just and reasonable rate charged by any other entity for a sale in the same geographic market for the same or most nearly comparable time period. See "—POWER BUSINESS LINE—Customers and Other Power Contract Parties of Bonneville's Power Business Line—Effect on Bonneville of Developments in California Power Markets in 1999-2001."

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue and enforce mandatory reliability rules that cover all users, owners and operators of the bulk power system. The provision would apply to Bonneville, but the Act expressly states that neither the ERO nor FERC are authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.

Fiscal Year 2006 Developments

Unaudited Quarterly Report for the Three Months Ended December 31, 2005

For the three months ended December 31, 2005 ("2006 First Quarter"), Bonneville's modified net revenues increased by about $34 million, or 53 percent, when compared to the same period in the prior fiscal year. 2006 First Quarter revenues from sales of power and transmission increased by about $71 million, or ten percent, and 2006 First Quarter expenses increased by about $29 million, or five percent, in each case when compared to same period in the prior fiscal year. Revenues increased in part because transmission revenues increased as higher transmission rates became effective on October 1, 2005. In addition, power revenues increased because of comparatively greater amounts of discretionary power sales at higher prices. Expenses increased because of comparatively higher operations and maintenance expense and somewhat greater purchased power expense as Bonneville bought some power at comparatively higher prices to protect against the possibility of low water conditions later in the fiscal year. For further information regarding fiscal year 2006 First Quarter unaudited results, see Appendix B-2 entitled "FEDERAL SYSTEM UNAUDITED REPORT FOR THE THREE MONTHS ENDED DECEMBER 31, 2005."

Year End Financial Forecast for Fiscal Year 2006

Current analyses prepared outside of Bonneville but relied on by Bonneville indicate a water supply forecast for the Columbia River basin of 137 million acre-feet (99 percent of the 30-year average) for fiscal year 2006. Historically, runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation conditions in the Pacific Northwest and British Columbia. Current forecasts of runoff are preliminary indicators only and actual results could differ substantially from the projections.

Based on expected revenues and expenses as of the end the first quarter of fiscal year 2006, Bonneville also currently believes that there is a very high probability that Bonneville will meet its fiscal year 2006 United States Treasury payment responsibilities on time and in full. Bonneville also expects that it will have positive modified net revenues in fiscal year 2006, based in part on assumptions of near average water conditions and actual and forecasted prices for surplus energy that are higher than previously forecasted. Such projections, beliefs and forecasts are preliminary and actual results could differ substantially therefrom.

President's Fiscal Year 2007 Budget

On February 6, 2007, the President presented to Congress the Federal Budget for fiscal year 2007 (the "2007 Budget"). Included in the 2007 Budget are several items that relate to Bonneville. First, the 2007 Budget provides that an amount equivalent to increased net secondary market revenues in excess of $500 million per year are assumed, beginning in fiscal year 2007, to be used to make advance amortization payments to the United States Treasury on Bonneville's bond obligations to the United States Treasury, consistent with both the President's Budget and the sound business practices required under the Transmission System Act. The 2007 Budget projects that net secondary market revenues above $500 million would total $924 million in aggregate in fiscal years 2007 through 2016. The proposed advance amortization payments would be payable from Bonneville's net proceeds, as is the case with Bonneville's other payments to the United States Treasury. See "BONNEVILLE FINANCIAL OPERATIONS—Order In Which Bonneville's Costs Are Met." An advance amortization payment would only occur for a fiscal year in which Bonneville's actual net secondary market revenues exceed $500 million. In addition, the 2007 Budget assumes that Bonneville will forecast a non-Federal debt service expense reduction in aggregate of about $382 million, to reflect the 2006 and 2007 anticipated Debt Optimization refinancing of Energy Northwest debt obligations, as has already been proposed by Bonneville. The 2007 Budget anticipates that through the foregoing actions Bonneville would eventually pay down about $1.3 billion in the outstanding principal amount of United States Treasury bonds, thereby making the associated borrowing capacity available for use to meet Bonneville's capital program needs. While all of the details of the proposal have not been determined, Bonneville estimates that on a probabilistic basis, the proposal would not increase rate levels in fiscal year 2007 but thereafter could increase its power rate levels for some period by about ten percent over what they would otherwise be. However, this rate impact would be offset by ratepayer benefits in future years. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Proposed Power Rates for Fiscal Years 2007 through 2011."

The 2007 Budget also references a proposal for legislation in calendar year 2005 under which an overall dollar limit would be enacted to cap the aggregate amount of direct and indirect debt obligations that Bonneville may have outstanding at any one time. The amount of the cap is proposed to be $4.45 billion (equal to Bonneville's current United States Treasury borrowing limit) increasing to $4.65 billion in fiscal year 2009. Under the proposal, the cap would apply to the aggregate amount of (i) the principal amount of outstanding bonds issued by Bonneville to the United States Treasury, and (ii) the outstanding principal amount of non-Federal debt obligations secured by a Bonneville payment commitment if the debt is issued and the commitment is incurred after the effective date of the proposed legislation. Among the indirect obligations that would count against the cap would be future Net Billed Bonds issued for purposes of financing renewals of, repairs to, and replacements of components of the Net Billed Projects, and the principal amounts of obligations associated with future lease-purchase agreements or similar capitalized contracts. The draft legislation would exclude from the cap the principal amount of all obligations incurred or bonds issued prior to the effective date of the proposed legislation and all future debt for the refinancing of Net Billed Bonds, including bonds or other debt issued in connection with the Debt Optimization Program. Although the Administration sent the proposed legislation to Congress in the summer of 2005, the bill has not been formally introduced in Congress.

The 2007 Budget also states that the "Administration supports private-public partnerships and believes that liabilities that the U.S. Government incurs as a result of such partnerships should be properly reflected from a budgeting standpoint. The 2007 Budget also provides that the Administration will continue to evaluate the appropriate borrowing authority level for Bonneville and will propose any changes in that limit on borrowing authority in future years." Elsewhere the 2007 Budget provides that Bonneville will "submit for approval by the Secretary of Energy or his designee alternative financing proposals by Bonneville for nonfederal participation and joint-financing of its transmission upgrades and other related investments."

POWER BUSINESS LINE

Bonneville's Power Business Line is responsible for marketing the electric power of the Federal System, providing oversight to electric power resources of the Federal System, and purchasing and exchanging Federal System power. The Power Business Line was responsible for about $2.7 billion in revenues, or 84 percent of Bonneville's total revenues, in Fiscal Year 2005.

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 by Federal law or policy to power generation. Such projects were constructed and are operated by the Corps or Reclamation. 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

The share of hydropower from Federally-owned hydroelectric projects for 2007 is estimated to be approximately 80 percent of Bonneville's total 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 2007."

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 is continuously available from the Federal System during adverse water conditions to meet Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e.*, a 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 (measured in megawatts) and firm energy (measured in average megawatts). Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2007, the Federal System, including about 870 average annual megawatts of firm energy from transfers and exchanges (and a small portion attributable to the last months in which Augmentation Agreement purchases are in effect), would be capable of producing about 8730 average annual megawatts of firm energy under certain assumptions of low water conditions. In conducting loads and resources evaluations Bonneville utilizes the term "Operating Year," meaning the 12 months beginning each August 1. See the table "Operating Federal System Projects For Operating Year 2007."

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 and water conditions its peaking capacity, for long-term planning purposes, will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because as Bonneville acquires or augments to balance annual and seasonal firm energy needs with new resources or purchases, these resource additions will also contribute more peaking capacity. At this time, 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. As additional non-power requirements are placed on the Federal System hydroelectric operations and as peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity resources or purchases to meet peak loads.

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

In general, for long-term resource planning purposes Bonneville estimates the amount of electric power it will acquire to meet loads above the expected Federal System firm power generated under certain low water conditions. For ratemaking and financial planning purposes, however, Bonneville takes into account the amount of electric power it expects to have available to market based on average water conditions. The energy that Bonneville has to market above critical water assumptions in a specified period is referred to as seasonal surplus energy. The amount of seasonal surplus energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2007, assuming average water conditions (median water flows), the Federal System is estimated to generate an annual energy surplus of about 2300 average annual megawatts. In wet water conditions (high water flows) the amount of annual energy surplus could be as much as 3550 average annual megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small.

Under the Slice of the System contracts, for the ten years beginning October 1, 2001, Slice customers purchased from Bonneville, for their requirements, an aggregate 22.63 percent proportionate interest of the output of both firm power and seasonal surplus energy of specific Federal System resources. The Slice customers purchase such an interest at a power rate intended to recover the same proportion of identified Federal System generating costs. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Preference Customer and Federal Agency Loads." As a result, Bonneville believes that its power sales revenues from seasonal surplus energy are somewhat less subject to the impact of hydroelectric generation variability and market prices than was the case prior to the commencement of sales under the Slice of the System contracts.

The Corps and Reclamation 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 estimates the operation of the Federal System under the Pacific Northwest Coordination Agreement ("PNCA"). The PNCA defines the planning and operation of Bonneville, U.S. Pacific Northwest utilities and other parties with generating facilities within the Region's hydroelectric system. The hydro-regulation study incorporated measures from the National Oceanographic and Atmospheric Administration Fisheries ("NOAA Fisheries") biological opinions relating to the Columbia River and tributaries and a U.S. Fish and Wildlife Service ("Fish and Wildlife Service") biological opinion, for the Snake River and Columbia River dams. These measures include increased flow augmentation for juvenile fish migration in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the Lower Snake and Columbia River dams to provide for non-turbine passage routes for juvenile fish migrants, and additional flows for Kootenai River white sturgeon in the spring. As new biological opinions (see "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—The Endangered Species Act," and "—2000 and 2004 Biological Opinions") and similar non-power requirements are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in estimates of the availability of Federal hydropower under all water conditions.

Other Power Resources

The balance of the Federal System includes, among other resources, nuclear power from the Columbia Generating Station, an 1150 megawatt nuclear generating station owned and operated by Energy Northwest. The Columbia Generating Station has the largest capacity for energy production of the non-Federal resources. The Columbia Generating Station operates under a two-year maintenance and refueling schedule, and refueling occurred in Operating Year 2005. Accordingly, for Operating Year 2007, the estimated output of the Columbia Generating Station assumes scheduled downtime for refueling and maintenance. In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. Bonneville projects that it will continue to have long-term contracts for transfers and exchanges that provide roughly 800-850 average annual megawatts. Previously, contract purchases were substantially greater because Bonneville used short-term power purchase agreements (Augmentation Agreement purchases) to obtain electric power needed to meet the increased loads taken on by Bonneville under the Subscription Strategy in fiscal years 2002 through 2006. Bonneville's generation estimates for the Federal System in Operating Year 2007 reflect that the Augmentation Agreement purchases have expired or been terminated, or will expire no later than December 31, 2006.

Operating Federal System Projects for Operating Year 2007

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, stream-flow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a 50 year record of river flows based on the period from 1929-1978 for planning purposes. During this historical period, low water conditions ("Low Water Flows") occurred in 1936-37, median water conditions ("Median Water Flows") occurred in 1957-58 and high water conditions ("High Water 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 2007, the Federal System January capacity ("Peak Megawatts" or "Peak MW") and energy capability using Low Water Flows, Median Water Flows and High Water 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, plant capacity factors, and maintenance schedules.

Operating Federal System Projects for Operating Year 2007(1)

Project	Initial Year in Service	No. of Generating Units	January Capacity (Peak MW)(2)	Maximum Energy (aMW)(3)	Median Energy (aMW)(4)	Firm Energy (aMW)(5)
United States Bureau of Reclamation Hydro Projects						
Grand Coulee incl. Pump Turbine	1941	33	6,534	3,164	2,475	1,961
Hungry Horse	1952	4	361	126	102	77
Other Reclamation Projects(6)		16	225	164	156	130
1. Total USBR Projects		53	7,120	3,454	2,733	2,169
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,535	1,678	1,353	1,073
John Day	1968	16	2,484	1,476	1,103	801
The Dalles including Fishway(7)	1957	24	2,079	1,078	830	603
Bonneville including Fishway	1938	20	1,059	597	543	365
McNary	1953	14	1,127	746	702	527
Lower Granite	1975	6	930	454	341	218
Lower Monumental	1969	6	923	444	312	221
Little Goose	1970	6	928	441	321	215
Ice Harbor	1961	6	693	380	267	137
Libby	1975	5	566	302	221	169
Dworshak	1974	3	444	234	190	126
Other Corps Projects(8)		20	398	299	272	227
2. Total USACE Projects		153	14,166	8,129	6,455	4,682
3. Total USBR and USACE Projects (line 1 + line 2)		**206**	**21,286**	**11,583**	**9,188**	**6,851**
Non-Federally-Owned Projects						
Columbia Generating Station(9)	1984	1	1,150	877	877	877
Other Non-Federal Hydro Projects(10)		5	35	59	47	45
Other Non-Federal Projects(11)		11	32	94	94	94
4. Total Non-Federally-Owned Projects		**17**	**1,217**	**1,030**	**1,018**	**1,016**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases(12)		**n/a**	**469**	**870**	**870**	**870**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**223**	**22,792**	**13,483**	**11,076**	**8,737**

Source: 2004 Pacific Northwest Loads and Resources Study, Bonneville, December 2004.

(1) Operating Year 2007 is August 1, 2006 through July 31, 2007. Discrepancies from the figures portrayed in the "2004 Pacific Northwest Loads and Resources Study" are mainly due to rounding.

(2) January capacity is the maximum generation to be produced under Low Water 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. Bonneville further reduces estimates of its hydro peaking

capacity to reflect that the hydro system has more machine capacity in its generating units than fuel (river flows) available to operate all units on a continuous basis.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows for energy in average megawatts. The hydro-regulation study incorporates measures from the 2004 Biological Opinion, defined hereinafter, and the Fish and Wildlife Service's 2000 Biological Opinion. The effects of the 2004 Biological Opinion were incorporated into these hydro-regulation studies, although the 2004 Biological Opinion has been set aside by court order. If and to the extent the effects of a new biological opinion are different than assumed under the 2004 Biological Opinion such changes will be reflected in future hydro-regulation studies. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Endangered Species Act—2000 and 2004 Biological Opinions."

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

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

(6) Other Reclamation Projects include: Palisades (1957), Anderson Ranch (1950), Chandler (1956), Green Springs (1960), Minidoka (1909), Black Canyon (1925), Roza (1958) and Boise Diversion (2004).

(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 Fishway Project is non-Federally-owned.

(8) Other Corps Projects include: Albeni Falls (1955), Big Cliff (1954), Cougar (1964), Detroit (1953), Dexter (1955), Foster (1968), Green Peter (1967), Hills Creek (1962), Lookout Point (1954) and Lost Creek (1975).

(9) Columbia Generating Station operates under a two-year maintenance and refueling schedule. For Operating Year 2007, the estimated output of the Columbia Generating Station was reduced to reflect scheduled maintenance and refueling. In Operating Years in which no refueling outage is scheduled, Bonneville assumes that the Columbia Generating Station will provide about 1000 annual average megawatts.

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

(11) Other Non-Federal Projects include the following projects: the Georgia Pacific Paper's Wauna Cogeneration Project (1996) (formerly, James River Wauna), the State of Idaho DWR's Clearwater Hydro (1998) and Dworshak Small Hydro (2000) projects, U.S. Park Service's Glines Canyon Hydro (1927) and Elwah Hydro (1910) projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), and Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, and a share of the City of Ashland's solar project. Calpine's Fourmile Hill Geothermal project has been postponed to October 1, 2010.

(12) Bonneville Contract Purchases include certain Subscription Strategy Augmentation Agreement purchases that remain in effect for a short period in Operating Year 2007 and other contracts for power from both inside and outside the Region, including Canada.

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 power sales 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."

Bonneville has a large number of parties with whom it has commercial arrangements including, but not limited to, arrangements for the purchase, sale and/or exchange of power, transmission and related services. Credit risk may be concentrated to the extent that one or more groups of counterparties, including purchasers and sellers, in power transactions with Bonneville have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to the circumstances which relate to other market participants which have a direct or indirect relationship with such counterparty. Bonneville seeks to mitigate credit risk (and concentrations thereof) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, defaults by counterparties occur from time to time. To date, no such default has had a material adverse effect on Bonneville. Bonneville continues to actively monitor the creditworthiness of counterparties with whom it executes wholesale energy transactions and uses a variety of risk mitigation techniques to limit its exposure where it believes appropriate.

Preference Customers

Preference Customers, which consist of qualifying publicly-owned utilities and consumer-owned electric cooperatives within the Region, are entitled to a statutory preference and priority ("Public Preference") in the purchase of available Federal System power for their requirements. These customers are eligible to purchase power at Bonneville's favorable "Priority Firm Rate" (or "PF Rate") for most of their loads, and as a class are Bonneville's principal customer base. Under Public Preference, Bonneville must meet a Preference Customer's request for available Federal System power in preference to a competing request from a non-preference entity for the same power. In the opinion of Bonneville's General Counsel, the Public Preference does not compel Bonneville to lower the offered price of uncommitted surplus Bonneville power to Preference Customers before meeting a competing request at a higher price for such uncommitted power from a non-Preference entity. Bonneville also sells relatively small amounts of power to several Federal agencies in the Region. While such Federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at the PF Rate.

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. Almost all of Bonneville's service to DSIs has been to aluminum smelting or processing facilities. For several years prior to 1995, Bonneville's annual DSI firm loads averaged approximately 2800 average annual megawatts. Through the implementation of the Subscription Strategy, Bonneville signed contracts with eight DSI companies to serve about 1500 average annual megawatts of loads for the five years ending September 30, 2006; however, the amount of power now being purchased by the DSIs is substantially less than the initially contracted amount in Subscription. Bonneville is proposing to make no physical power sales to DSIs in the 2007 Rate Period, except with respect to the sale of a small amount of power to one non-aluminum company DSI. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—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 Fiscal Years 2002 through 2006," "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data," and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

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

Exports of Surplus Power to the Pacific Southwest

Bonneville sells and exchanges power via the Pacific Northwest-Pacific Southwest Intertie (the "Southern Intertie") transmission lines to Pacific Southwest utilities, power marketers and other entities, which use most of such power to serve California loads. These sales and exchanges are composed of firm power and non-firm energy surplus to Bonneville's Regional requirements. Exports of Bonneville power for use outside the Pacific Northwest are subject to a statutory requirement that Bonneville offer such power for sale to Regional utilities to meet Regional loads before offering such power to a customer outside the Region. However, in the opinion of Bonneville's General Counsel, Bonneville is not required to reduce the rate of proposed export sales to meet a Northwest customer's request if the proposed export sale is at a higher FERC-approved rate than the Northwest customer is willing to pay.

In addition, Bonneville's contracts for firm energy and peaking capacity sales outside the Region include, as required by the Regional Preference Act, recall provisions that enable Bonneville to terminate such sales, upon advance notice, if needed to meet Bonneville customers' power requirements in the Region. With certain limited exceptions, Bonneville's sales of Federal System power out of the Region are subject to termination on 60 days' notice in the case of energy and on 60 months' notice in the case of peaking capacity. These rights help Bonneville assure that the power needs of its Regional customers are met. Power exchange contracts are not required to contain the Regional recall provisions.

In 1995, in view of the Regional load diversification away from Bonneville that was then occurring, Congress enacted a law that authorizes Bonneville to sell for export out of the Region a limited amount of power unencumbered 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 in declining amounts through fiscal year 2007. Bonneville does not thereafter expect to have excess Federal power to sell, at least through fiscal year 2011.

Pacific Southwest utilities typically account for the greatest share of purchases of seasonal surplus energy from Bonneville and these transactions 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 in some cases 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 in 1999-2001

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 2001, and Southern California Edison ("SCE"), also affected the financial condition of two entities with central roles in 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. Another such entity is the nonprofit California Power Exchange ("Cal-PX"), which suspended operations in 2001, but was theretofore responsible for operating a power exchange through which the Cal-IOUs were obligated to purchase virtually all of their power requirements. The Cal-PX filed for bankruptcy protection in March 2001.

The Cal-ISO and the Cal-PX have outstanding payment obligations to Bonneville for sales it made to them during 1999 and 2000. Bonneville estimates that its total exposure for unpaid sales under these agreements is about $84 million. Bonneville has 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 in 1999-2001, FERC initiated three proceedings to address, under the FPA, whether certain power sellers charged unjust and unreasonable prices and therefore should refund to power purchasers any amounts overcharged. Bonneville is participating in the three proceedings.

In one proceeding (the "Northwest Spot Market Docket"), FERC reviewed the extent to which the pricing of power sales in the bilateral "spot market" in the Pacific Northwest was "unjust and unreasonable" in certain periods in 2000 and 2001. A FERC-appointed administrative law judge for the Northwest Spot Market Docket made recommendations to FERC concluding, among other things, that the prices charged in the bilateral "spot market" in the Pacific Northwest during the relevant period were not unjust and unreasonable, that refunds should not be ordered, and that FERC should conduct no further hearings and should terminate the proceeding. Parties filed petitions for rehearing and FERC issued an order on November 11, 2003, denying the petitions and affirming the judge's recommendations. Appeals challenging the order have been filed in the Ninth Circuit Court.

In a second related proceeding (the "Show Cause Proceeding"), FERC announced in February 2002, that it was investigating whether any entity, including Bonneville, manipulated short-term electric power and natural gas prices in the West or otherwise exercised undue influence over wholesale prices in the West, from the period January 1, 2000 forward. On June 25, 2003, FERC issued Show Cause Orders to over 60 Identified Entities in the Cal-ISO and Cal-PX markets. The Show Cause Orders require such entities to show why certain market activities did not constitute gaming practices. Bonneville was named as an Identified Entity. After entering into discussions with Bonneville over the allegations contained in the Show Cause Order, FERC staff has moved FERC to dismiss the matter against Bonneville. On January 22, 2004, FERC upheld the dismissal of the Show Cause order issued on June 25, 2003. Certain parties filed for rehearing of the matter and FERC denied the rehearing request. The parties appealed the matter to Federal appellate court and FERC has moved to dismiss the appeal. The Federal appellate court has not yet rendered a decision on the motion to dismiss the appeal.

In a third proceeding (the "California Refund Docket"), FERC reviewed the extent to which (i) the prices of power sales through the Cal-PX and to the Cal-ISO were "unjust and unreasonable" in certain periods in 2000 and 2001 and (ii) various power sellers that participated in such sales would be required to provide refunds. Bonneville was a net seller through the Cal-PX and to the Cal-ISO during the period at issue and FERC concluded that Bonneville had refund liability for such sales. In 2005, the Ninth Circuit Court reversed FERC, holding instead that FERC lacked authority to order Bonneville to provide refunds. Thereafter, in December 2005, the California Attorney General, and others filed administrative claims with Bonneville alleging that Bonneville had a contractual obligation to abide by FERC's refund determinations and demanding refunds. If Bonneville rejects the administrative claims, the claimants would be entitled to file litigation for breach of contract against Bonneville under the Federal Contract Disputes Act. The total amount of the claims against Bonneville is in excess of $160 million. These claims have not yet proceeded to litigation.

For a description of litigation between SCE and Bonneville arising out of developments in West Coast energy markets in 1999-2000, see "BONNEVILLE LITIGATION—SCE Litigation."

In a related development, in Fiscal Year 2005 Congress enacted a new law that subjects Bonneville to FERC jurisdiction on a prospective basis for purposes of establishing refund liability. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

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 to a DSI.

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. With respect to Bonneville's proposal to manage its statutory duty to meet certain load requirements in the five-year period after fiscal year 2006, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Loads and Related Contracts and Power Rates for the Period Fiscal Years 2002 through 2011."

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 the Regional IOUs 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.

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.

Federal System Load/Resource Balance. In order to determine whether Bonneville will have to obtain additional electric power resources on a planning basis, and to determine the amount of firm power that Bonneville may have to market apart from committed loads, Bonneville periodically estimates the amount of load that it will be required to meet under its contracts.

Bonneville's loads and resources are subject to a number of uncertainties over the coming years. Among these uncertainties are: (i) the level of loads and types of loads placed on Bonneville under the provisions of the Northwest Power Act; (ii) the amount of power purchases and resource acquisitions 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. For a description of loads and resources see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION."

Bonneville's Authority to Add Resources. In order to meet the foregoing power sales obligations, Bonneville may have to obtain electric power from sources in addition to the existing Federal System hydroelectric projects and existing non-Federally-owned generating projects, the output of which Bonneville has acquired by contract. By law, Bonneville may not own or construct generating facilities. However, the Northwest Power Act authorizes Bonneville to acquire resources to serve firm loads pursuant to certain procedures and standards set forth in the Northwest Power Act. "Resources" are defined in the Northwest Power Act to mean: (1) electric power, including the actual or planned electric power capability of generating facilities; or (2) the actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from conservation measures. "Conservation" is defined in the Northwest Power Act to mean measures to reduce electric power consumption as a result of increased efficiency of energy use, production or distribution.

Bonneville's statutory responsibility to meet its firm power contractual obligations may lead Bonneville to acquire additional power and conservation resources. The extent to which Bonneville does so will depend on the effects of the competitive wholesale electric power market, load growth and other factors.

The acquisition of resources under the standards and procedures of the Northwest Power Act, however, is not the sole method by which Bonneville may meet its power requirements. Other methods are available. These include, but are not limited to: (1) exchange of surplus Bonneville peaking capacity for firm energy; (2) receipt of additional power from improvements at Federally and non-Federally-owned generating facilities; and (3) purchase of power under the Transmission System Act for periods of less than five years.

Bonneville's resource acquisitions under the Northwest Power Act are guided by a Regional conservation and electric power plan (the "Power Plan") prepared by the Northwest Power and Conservation Council (the "Council"). The governors of the states of Washington, Oregon, Montana and Idaho each appoint two members to the Council, which is charged under the Northwest Power Act with developing and periodically amending a long range power plan to help guide energy and conservation development in the Region. The Power Plan sets forth guidance for Bonneville regarding implementing conservation measures and developing generating resources to meet Bonneville's Regional load obligations. The Council also develops and periodically amends a fish and wildlife program for the Region. See "Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife."

Bonneville's Resource Strategies. Increased competition, deregulation in the electric power market and loss of hydropower flexibility due to Endangered Species Act ("ESA") constraints have major implications for Bonneville's resource acquisition strategy. While Bonneville believes that it is substantially in load resource balance on a planning basis through fiscal year 2011, it is possible that Bonneville may need to acquire additional power. Given uncertainties over the amount of loads that Bonneville will be required to meet, especially in the period after fiscal year 2011, any resource investment that involves irrevocable, high fixed costs over a period longer than Bonneville's contracted load obligation is much riskier than it would have been in the past. Bonneville has indicated to Regional interests that Bonneville would prefer in the future to avoid assuming the responsibility of meeting incremental Regional power loads above the generating capability of the existing generating resources of the Federal System. Bonneville has also indicated that in the post-2011 period it will consider using tiered power rates under which the anticipated higher cost of electric power from new power purchases to meet such incremental loads would be recovered from customers to the extent they place incremental load obligations on Bonneville. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION."

Short-Term Power Purchases. As noted, Bonneville's current policy is to encourage Regional Customers to meet their own incremental loads. Nonetheless, should Bonneville assume incremental load obligations above the existing generating resources of the Federal System, Bonneville believes that, in general, new resources should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available and should have costs that can be offset when hydroelectric power is available. Short-term (less than five year) purchases are the only type of resource that meets this resource acquisition strategy. Short-term purchases almost always will fit these conditions better than other resources, including long-term combustion turbine resources, because purchases generally do not involve incurring high, long-term fixed costs.

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

A short-term purchase strategy can lead to fluctuating revenues and/or revenue requirements. In dry years, Bonneville's revenue requirements could increase as it could be forced to spend a significant amount of money for short-term purchases to meet loads, to the extent that Bonneville had not previously purchased power therefor. In wet years, purchase requirements can be significantly reduced as Bonneville would meet more of its loads with non-firm hydroelectric power.

In contrast to a reliance on long-term resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville would over-commit to long-term purchases and be forced to sell consequent surpluses at low prices in the market. Nonetheless, it is still possible, even with a short-term purchase strategy, that Bonneville could purchase more energy than needed and have to sell consequent surpluses at low prices. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation.

Renewable Energy. Bonneville presently purchases a total of approximately 50 average megawatts from various wind energy projects in Wyoming, Oregon, and Washington, and small amounts of power from solar photovoltaic projects. Bonneville also has contracted to purchase 49.9 megawatts from a geothermal project under construction in northern California. The geothermal project was originally scheduled to become operational in December 2005 but it is not clear yet whether the site contains a viable geothermal resource. The developer has until July 2008 to determine whether the site is viable and the commercial operation date has been extended to July 2010.

In light of its strategic objective of limiting sales at its lowest-cost rates to approximately the firm capability of the existing Federal System, in 2005 Bonneville decided that it will not actively seek to acquire additional renewable resource output from specific projects. Nevertheless, Bonneville will spend up to $21 million annually on a program to encourage renewable resources. This program consists of direct programmatic costs, such as research and development activities, including long-term solar and wind data monitoring, the annual net (above market) costs of any acquisition of renewable resource project output, and to continue in the 2007 Rate Period a power rate discount program in which Bonneville provides limited rate credits to customers that pursue renewable resources.

Electric Power Conservation. Bonneville also encourages electric power conservation measures. Bonneville currently provides, and is proposing to continue to provide during the 2007 Rate Period, a $.50 per megawatt-hour rate discount to those of its customers that implement conservation measures. In addition, Bonneville has a target of acquiring approximately 50 annual average megawatts of conservation annually during fiscal years 2007 through 2011. Such resource development should lessen Bonneville's reliance on spot market power purchases.

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, which 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 is to "purchase power" offered by an exchanging utility at its "average system cost," which is determined by Bonneville through the application of a methodology 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 is then to offer an identical amount of power for "sale" to the utility for the purpose of resale to the exchanging utility's residential users. In reality, no power would change hands. Bonneville would make 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 Residential Exchange Program Rate if such 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 Program obligation with respect to such utilities for the period July 1, 2001 through September 30, 2011. Bonneville's settlement of its Residential Exchange obligations was later challenged in court. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Bonneville has also settled its Residential Exchange Program obligations with one qualifying Preference Customer. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Residential Exchange Program Obligations."

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by Federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program (the "Council Program"). In addition, in the wake of certain listings of fish species under the ESA as threatened or endangered, Bonneville is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the NOAA Fisheries and the Fish and Wildlife Service in furtherance of the ESA.

Bonneville typically funds fish and wildlife mitigation through several mechanisms. Since the creation of the Federal System, Bonneville has repaid the United States Treasury the share of the costs of mitigation by the Corps and Reclamation that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the Federal 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, Reclamation and Bonneville; and, (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation for Federal System projects.

"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 Fiscal Year 2005, Direct Costs and Replacement Power Purchase Costs in aggregate were about $394 million and Foregone Power Revenues were about $182 million.

The Endangered Species Act. As noted above, Bonneville, the Corps and Reclamation 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 Reclamation, 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 twelve 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 Reclamation 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 Reclamation generally demonstrate that jeopardy to listed species is being avoided. Specifically, Bonneville, the Corps and Reclamation 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 have been and are the subject of litigation and 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 that 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.

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. Bonneville estimates that the total of Direct Costs and Operational Impacts was about $501 million in fiscal year 2004 and about $576 million in Fiscal Year 2005.

2000 and 2004 Biological Opinions. In December 2000, NOAA Fisheries promulgated a biological opinion ("2000 Biological Opinion") that superseded all previous opinions issued by it concerning the Federal System hydroelectric dams. The 2000 Biological Opinion was coordinated with a Fish and Wildlife Service biological opinion issued in 2000 relating to certain other species. The 2000 Biological Opinion included a number of measures affecting Federal System dam operations and dam configurations in order to improve anadromous fish passage survival through the hydro system.

Included among the 13 biological opinion alternatives around which Bonneville developed its 2002 Final Power Rates were several alternatives 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 annual average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales.

A number of interests filed litigation in connection with the 2000 Biological Opinion. In May 2003, the United States District Court for the District of Oregon ruled that the 2000 Biological Opinion was inadequate (i) because it relied on offsite mitigation measures that were "not reasonably certain to occur" and (ii) because the "action area" (geographic delineation of where operations directly or indirectly affect listed species) was incorrectly described. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. On November 30, 2004, NOAA Fisheries finalized a "2004 Biological Opinion" to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court.

The 2004 Biological Opinion called for multi-million dollar improvements in fish passage facilities at Federal dams on the Snake and Columbia rivers over the next ten years. In addition, the 2004 Biological Opinion called for enhanced efforts to reduce predation on juvenile salmon, improvements in downstream transportation of migrating salmon, and changes in fish hatchery operations. Federal agencies, including Bonneville, the Corps and Reclamation, estimated a total spending commitment of over $6 billion over the planned ten-year life of the 2004 Biological Opinion. This amount is roughly equivalent to forecasted spending under the 2000 Biological Opinion. As with the 2000 Biological Opinion, the 2004 Biological Opinion did not recommend implementation of dam breaching. In the opinion of the General Counsel to Bonneville, legislation by Congress would be required in order for the breaching of the dams to be authorized.

A number of interests filed litigation challenging the 2004 Biological Opinion. In October 2005 the United States District Court for the District of Oregon invalidated the 2004 Biological Opinion on a number of grounds and remanded the 2004 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. The court's order gave NOAA Fisheries one year to redress the deficiencies in the 2004 Biological Opinion. The Federal Government has filed a notice of appeal of the court's ruling with the Ninth Circuit Court. NOAA Fisheries is in the process of preparing a new biological opinion. Bonneville is unable to predict what the new biological opinion will provide or the financial consequences thereof to Bonneville. Bonneville believes, however, that the new biological opinion is likely to expand the types and number of actions that will be required to benefit listed species.

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 $38 million, $97 million, $77 million and $58 million in fiscal years 2002, 2003, 2004 and 2005, respectively. These recoupments (also referred to as "4(h)(10)(C) credits") are treated as revenues in Bonneville's ratemaking process, and such recoupments are taken against Bonneville's payments to the United States Treasury. The recoupments are initially taken based on estimates and are subsequently modified to reflect actual data. Two important costs that may be recouped under section 4(h)(10)(C) are the cost of Foregone Power Revenues and Replacement Power Purchases arising from certain hydroelectric system operations for the benefit of fish and wildlife. Both of these categories of costs can occur to a greater degree in dry years when, historically, market prices for power are comparatively high. Thus, Bonneville believes that the amount of 4(h)(10)(C) credits will tend to be greater in dry years when power prices tend to be high and Bonneville has less power to market, and therefore tends to have lower power revenues. (The figures relating to 4(h)(10)(C) credits in fiscal year 2003 exclude about $78 million in fish and wildlife credits under an arrangement referred to as the Fish Cost Contingency Fund. See "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results—Fiscal Year 2004" and "—Fiscal Year 2003.")

Council's Fish and Wildlife Program. In 2000, the Council revised and adopted a new Columbia River Basin Fish and Wildlife Program (the "2000 Program"). The Council amended the 2000 Program in 2003 with "mainstream amendments" meant primarily to address mitigation issues related to operation of the Federal System. In 2005, the Council amended the 2000 Program to help focus mitigation actions on overcoming environmental limitations to increased fish and wildlife populations.

The 2000 Program focuses on an ecosystem approach to rebuilding fish and wildlife in the Columbia River basin, consistent with the applicable biological opinions. Thus, the 2000 Program set forth an "integrated program" for both the Council Fish and Wildlife Program and the off-site mitigation actions called for under the 2000 Biological Opinion. The costs of the integrated program ("Integrated Program Costs") are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General." The 2000 Program as amended now reflects the 2004 Biological Opinion.

In response to financial developments, in October 2003, Bonneville reiterated, and the Council confirmed, an average expense accrual budget level of $139 million per year for the expense portion of Bonneville's Integrated Program Cost obligation under the Council's Program for fiscal years 2003 through 2006. This level is in the range of projected costs assumed in Bonneville's 2002 Final Power Rates. In June 2003, the Yakama Nation, a tribal entity, filed a petition in the Ninth Circuit Court to request a review of Bonneville's fish and wildlife fund levels. The Yakima Nation has not yet prosecuted its case and it remains stayed. See "BONNEVILLE LITIGATION—Yakama Nation Litigation."

For the 2007 Rate Period, Bonneville has proposed an average expense accrual budget level of $143 million per year for the expense portion of the Integrated Program Cost obligation under the Council's Program.

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 Programs or amendments thereto, or litigation relating to the foregoing.

Power Marketing in Fiscal Years 2002 through 2006

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. Under the Subscription Strategy, Bonneville entered into long-term Subscription Agreements through which it contracted to sell all of its then available firm power to Regional customers for various terms.

Preference Customer and Federal Agency Loads. Under the Subscription Strategy, Bonneville entered into long-term power sales contracts directly or indirectly to provide power to meet loads of about 127 Preference Customers, which contracts, in view of certain subsequent amendments, all run through fiscal year 2011. Bonneville also agreed to full requirements power sales agreements with eight Federal agencies to meet their loads, which, in aggregate, are estimated to be about 118 annual average megawatts.

Under the Subscription Strategy, Bonneville sells Preference Customers four basic power products: Block sales, Slice of the System, partial requirements and full requirements. "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Loads and Related Contracts and Power Rates for the Fiscal Years 2002 through 2011—Subscription and Related Power Rates for Fiscal Years 2002 through 2006."

Under the foregoing agreements, as amended, Bonneville estimates that it will be obligated to provide roughly 7150 to 7350 average megawatts to meet Preference Customer and Federal agency loads through fiscal year 2011. Of this amount, about 1600 average megawatts is sold as Slice of the System, about 2200 average megawatts is in the form of Block sales and the remainder is in the form of full or partial requirements service. 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 basin and actual generation from Federal System resources.

The Slice of the System (or "Slice") contracts require that customers make monthly payments based on forecasted costs of the Federal System, with specific exceptions. These monthly payments are subject to an annual "true up" adjustment for actual costs. Under provisions of the Slice contracts, certain Slice customers obtained an audit of the fiscal year 2002 "true up" adjustment and costs. The Slice customer audit asserted that the Slice customers' payments for fiscal year 2002 should be adjusted by removing $84 million from Bonneville's charges. Bonneville rejected some of the proposed adjustments and some of Bonneville's non-Slice customers filed litigation in the Ninth Circuit Court challenging Bonneville's rejection. Currently, Bonneville, the non-Slice customer litigants and the Slice customers are in settlement mediation on the matter. Bonneville made about $30 million in "true up" payments to Slice customers with respect to fiscal year 2003 and Slice customers did not conduct an audit. Slice customers made about $10 million in "true up" payments to Bonneville with respect to fiscal year 2004. The Slice customers have asked for an audit of the fiscal year 2004 Slice "true up" adjustment and costs. Depending on the results of the mediation, or alternatively the litigation, it is possible that the true-up payments with respect to subsequent fiscal years could also be adjusted. See "BONNEVILLE LITIGATION—Slice Litigation."

Residential Exchange Program Obligations. As part of the Subscription Strategy, Bonneville and the six Regional IOUs participating in the Residential Exchange Program entered into six separate ten-year contracts ("Residential Exchange Settlement Agreements") that settle Bonneville's statutory Residential Exchange Program obligations with respect to such utilities during the period July 1, 2001 through September 30, 2011. For the five years beginning October 1, 2001, Bonneville originally contracted to satisfy this obligation through (i) direct sales of 1000 average megawatts of firm power at a Residential Load Rate ("RL Rate") and a similar rate in the case of a comparatively small Regional IOU, and (ii) cash payments for an exchange value ("Monetary Benefits" as described immediately below) of 900 average megawatts of firm power. Under the 2002 Final Power Rates, the RL Rate is set at a level equivalent to Bonneville's lowest available requirements service rate, the PF Rate. The Monetary Benefits are based on the related amount of power multiplied by the difference between a forecast of the market price of power set in Bonneville's rate case and the RL Rate. All power sales and payments by Bonneville under the Residential Exchange Settlement Agreements, as amended, must be passed through in total to the Regional IOUs' residential and small farm loads in the Region. (The RL Rate is not to be confused with the Residential Exchange Program Rate, see "—Proposed Power Rates for Fiscal Years 2007 through 2011—Relationship of the 2007 Initial Power Rate Proposal to Slice of the System Power Sales and to Bonneville's Obligations with Respect to the Residential Exchange," and was established by Bonneville to effect the Residential Exchange Settlement Agreements.)

Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of contract amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2001. These amendments and arrangements increased the amount of cash payments that Bonneville would make with respect to the Residential Exchange Settlement Agreements and reduced the amount of physical power sales thereunder. As a result, the aggregate cash payments to Regional IOUs that Bonneville has made related to the Residential Exchange Settlement Agreements were about $353 million in fiscal year 2002, $304 million in fiscal year 2003, $367 million in fiscal year 2004, and $361 million is Fiscal Year 2005. Under a variety of assumptions, such payments are projected to be about $361 million in fiscal year 2006. As a result of the foregoing load reductions, Bonneville reduced its obligation to make physical power sales under the Residential Exchange Settlement Agreements to 258 average megawatts of power from fiscal year 2002 through fiscal year 2006. This remaining Residential Exchange Settlement Agreement power sale is to a single Regional IOU (Portland General) at the RL Rate, and is subject to the all three of the rate level adjustment mechanisms in the 2002 Final Power Rates, which are in effect through fiscal year 2006. See "—Subscription Power Rates for Fiscal Years 2002 through 2006." The power sale to Portland General for fiscal years 2003 through 2006 has an assumed benefit (market value of power minus power purchase costs) to PGE's residential and small farm customers of roughly $25 million to $60 million per year.

A component of Bonneville's settlement of the Residential Exchange Program obligations with Regional IOUs reflects payments for load reductions arising from contract amendments and certain other arrangements wherein Regional IOUs converted their rights to receive low cost power from Bonneville into rights to obtain cash payments from Bonneville. Certain of these payments are subject to further adjustment if there is not a settlement of certain litigation filed by Preference Customers challenging Bonneville's authority to enter into the Residential Exchange Settlement Agreements. In May 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements that reduced by one half the $200 million that would have been owed by Bonneville for the periods beginning October 1, 2006, if the aforementioned litigation is not resolved. In addition to the foregoing reduction in payments, Bonneville and such Regional IOUs agreed to permit Bonneville to defer until fiscal years 2007-2011 the payment of the remaining $100 million otherwise owed by Bonneville to the two Regional IOUs in fiscal years 2005 and 2006. In return, these two Regional IOUs obtained assurances from Bonneville as to the amount and nature of Residential Exchange Settlement Agreement benefits to be provided to them by Bonneville in fiscal years 2007-2011, as described below. In addition, the four other Regional IOUs obtained these same assurances from Bonneville.

In developing the Subscription process, Bonneville originally expected to meet its Residential Exchange Settlement Agreement obligations in the period after fiscal year 2006 in full by providing about 2200 average megawatts of electric power to the Regional IOUs.

As a result of May 2004 agreements, Bonneville will provide and the Regional IOUs will receive only Monetary Benefits and not physical power under the Residential Exchange Settlement Agreements in fiscal years 2007-2011, thereby reducing Bonneville's load uncertainty by roughly 2200 average megawatts in each of the five fiscal years. The aggregate financial benefits paid by Bonneville in fiscal years 2007-2011 will have a floor of $100 million per fiscal year and a maximum of $300 million per fiscal year, although Bonneville will also pay the aggregate deferred amount of $100 million (plus $6.5 million in interest) to Puget and PacifiCorp over the five-year period. Furthermore, in fiscal years 2007-2011, Puget and PacifiCorp will receive in aggregate a total of $18 million (plus interest) from Bonneville as a result of separate agreements in which Bonneville deferred certain payments to such utilities in fiscal year 2003. In addition, Bonneville and the six Regional IOUs have agreed to use an independently determined market price to determine Monetary Benefits in such period, rather than using market price indicators developed by Bonneville in its power rate cases, as was formerly agreed. As a result, the valuation of Bonneville's future obligation to provide Monetary Benefits to Regional IOUs will vary with market prices. Presently, Bonneville's market forecast indicates that Bonneville's payments to Regional IOUs with respect to the Residential Exchange Program (exclusive of the payment of the deferred amounts) will be about $300 million per year in fiscal years 2007, 2008 and 2009. The Residential Exchange Settlement Agreements and the subsequent amendments and agreements between Bonneville and the related Regional IOUs have been challenged in court by other Bonneville customers. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

<u>Residential Exchange Settlement with a Preference Customer</u>. In June 2005, Public Utility District No. 1 of Clark County, Washington ("Clark"), a large Preference Customer, notified Bonneville that Clark wished to receive benefits under the Residential Exchange provisions of the Northwest Power Act, and requested a contract for participation. In January 2006, Clark and Bonneville executed a settlement of their respective rights and obligations under the Residential Exchange Program through September 30, 2011. Under the settlement, Bonneville agreed to pay Clark $15 million in four installments through 2008 and Clark and Bonneville entered into a restated power sales requirements contract pursuant to which Bonneville's net cost of serving Clark's requirements through September 30, 2011 is reduced. Bonneville estimates that the cost to Bonneville of the Clark settlement is in the range of $2 million to $4 million.

As part of the proceeding for developing power rates for the 2007 Rate Period, Bonneville has identified five additional Preference Customers that have relatively high average system costs and that may seek or may be entitled to obtain Residential Exchange Program benefits. Bonneville is unable to predict whether or the extent to which it may become responsible for providing such additional Residential Exchange Program benefits; however, the aggregate amount of such customers' residential loads is approximately 500-600 average megawatts, less than double the size of Clark's residential load. Under Bonneville's initial power rate proposal for the 2007 Power Rate Period, the rate Bonneville would use for the cost of Federal System power it would exchange to utilities under the Residential Exchange Program (the "Residential Exchange Program Rate") is proposed to be substantially higher than the rate that is available for such transactions in the current power rate period. Bonneville believes that such proposed higher rate levels, if adopted in the 2007 Final Power Rate Proposal, would make it unlikely that any Preference Customers would seek to participate in the Residential Exchange Program during the 2007 Rate Period. See "—Proposed Power Rates for Fiscal Years 2007 through 2011—Relationship of the 2007 Initial Power Rate Proposal to Slice of System Power Sales and to Bonneville's Obligations with Respect to the Residential Exchange."

<u>DSI Loads</u>. In the past, 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 later agreements, the DSI loads Bonneville was obligated by contract to serve were reduced to roughly 1800 average megawatts through fiscal year 2001.

The Ninth Circuit Court has held that Bonneville no longer has a statutory obligation to sell any power to meet DSI loads. Nonetheless, as part of Bonneville's Subscription program for the post-fiscal year 2001 period, Bonneville entered into five-year take-or-pay power sales contracts with a number of aluminum company DSIs under which agreements such DSIs agreed to purchase approximately 1500 average megawatts in aggregate. Notwithstanding the original terms of the Subscription Agreements, Bonneville's sales to aluminum company DSIs in fiscal year 2006 are about 200-300 average megawatts due to contract amendments and the bankruptcy of several DSIs. See "BONNEVILLE LITIGATION—Kaiser Aluminum Bankruptcy."

With respect to service to the DSIs after fiscal year 2006, Bonneville decided in February 2005 that it would provide eligible DSIs some level of service, at a known quantity and capped cost, for fiscal years 2007 through 2011. In June 2005, Bonneville issued an additional policy (the "DSI ROD") relating more specifically to service to DSIs. Bonneville decided in the DSI ROD that, unless it determined after further review that the costs associated with court ordered fish mitigation measures required Bonneville to reduce or eliminate DSI benefits, it would offer new five-year power sales contracts totaling 560 megawatts to its three remaining aluminum company DSIs at a rate equivalent to Bonneville's lowest-cost priority firm power rate, but at an annual implied cost to Bonneville not to exceed $59 million. In order to meet this cost cap most efficiently, Bonneville indicated in the DSI ROD that it would also reserve the ability to monetize the value of the DSI power sales contracts by making cash payments to the DSIs in lieu of delivering low cost power.

Bonneville and three aluminum company DSIs have negotiated a draft form of power sales contract. Under the draft agreements Bonneville would make payments tied to each company's actual operating level and equal to the difference between an annually forecasted power market price and Bonneville's lowest-cost PF Rate for the first three years of the proposed agreements, which coincides with the term of the 2007 Rate Period. Bonneville would also reserve the right to convert each of the contracts to a physically delivered power sale for the final two years of the contracts' term. Bonneville expects to make a final determination in April 2006 as to the level of DSI benefits it will provide during the 2007 Power Rate Period, and whether to offer the draft contracts to the DSIs. See "—Customers and Other Power Contract Parties of Bonneville's Power Business Line—Direct Service Industrial Customers" and "BONNEVILLE LITIGATION—DSI Service ROD Litigation."

In addition to the foregoing proposal, Bonneville has proposed to continue to serve its only non-aluminum company DSI with a 17 megawatt power sales contract at a rate approximately equivalent to its lowest-cost PF Rate.

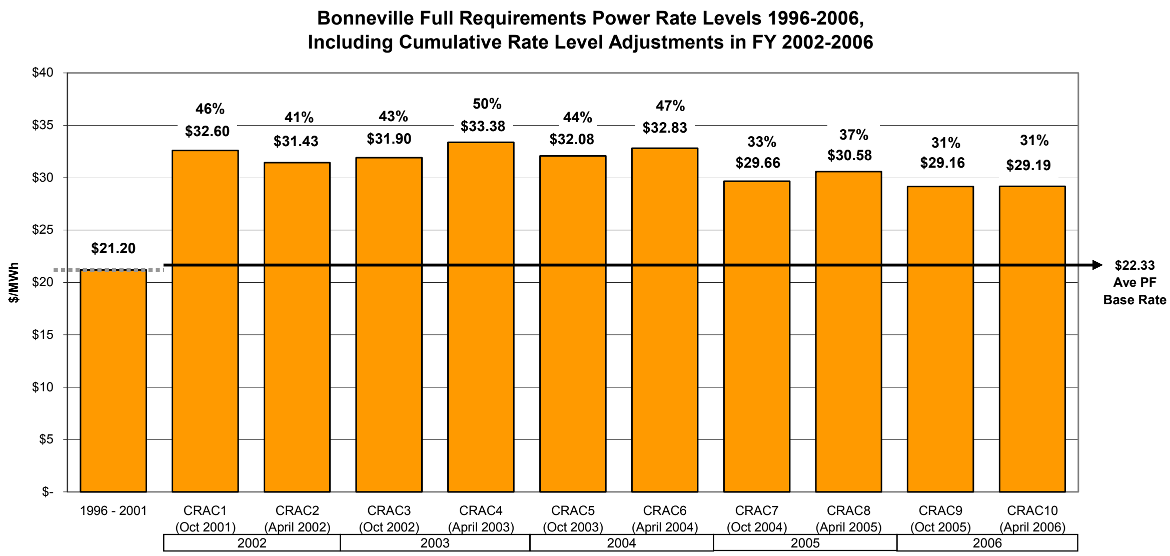
Subscription Power Rates for Fiscal Years 2002 through 2006. In June 2001, Bonneville filed with FERC Bonneville's 2002 Final Power Rate Proposal for the five years ending September 30, 2006. FERC subsequently granted final approval of such rates, although they have been challenged in litigation in the Ninth Circuit Court. The 2002 Final Power Rates include base rates applicable to the varying types of Subscription Agreements and certain rate level adjustments that increase or decrease power rate levels depending on certain conditions. The base rate levels are between approximately $19 per megawatt hour and $23 per megawatt hour, excluding transmission and depending on type of service. The base rates are at levels similar to those in effect for like service in the immediately preceding rate period. The 2002 Final Power Rates also include three rate level adjustments mechanisms under which Bonneville has varied power rate levels: the Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), the Financial Based Cost Recovery Adjustment Clause ("FB-CRAC"), and the Safety Net Adjustment Clause ("SN-CRAC").

The LB-CRAC was designed to recover the net cost of system Augmentation Agreement purchases and certain load reduction agreements. The LB-CRAC is based on periodic forecasts of Bonneville's cost of Augmentation Agreement purchases and certain related costs for consecutive six-month periods during the five-year rate period. The LB-CRAC is revised each six-month period during the rate period to reflect updated forecasts of Augmentation Agreement purchase costs and load reduction costs in the next six months. Another adjustment to the amounts recovered under LB-CRAC reflects actual costs of Augmentation Agreement purchases in the prior six-month period to the extent that the forecast for such augmentation costs differ from actual costs in such period.

The FB-CRAC was designed to restore, on a forecasted basis, Bonneville's financial reserves to certain fiscal year-end reserve levels. The FB-CRAC was designed to be implemented for an entire fiscal year if Bonneville's financial forecast made in the third quarter of the prior fiscal year indicated that the accumulated modified net power revenues for the beginning of the subject fiscal year would be below the accumulated modified net power revenue equivalent of the applicable reserve target. Modified net power revenues are net Power Business Line revenues from operations less (i) the effects of the Debt Optimization Program and other debt management actions relating to Energy Northwest, and (ii) unrealized mark-to-market gains or losses under the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard No. 133 ("SFAS 133"). See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Bonneville's Fiscal Year 2005 Financial Results." The FB-CRAC did not go into effect in fiscal year 2002 or 2006 but it recovered roughly $100 million per year in additional revenue in fiscal years 2003 through 2005.

The SN-CRAC was designed to permit Bonneville to design and establish a rate level increase if Bonneville were to forecast a 50 percent probability or greater of missing a scheduled payment to the United States Treasury among other specified reasons. In early fiscal year 2003 Bonneville determined that the preceding condition had been met and thereafter issued a final proposal for an SN-CRAC rate level adjustment (the "2004 SN-CRAC Rate Level Adjustment"). The 2004 SN-CRAC Rate Level Adjustment was designed to adjust rate levels on a variable basis for a fiscal year if Bonneville were to forecast that its Power Business Line accumulated modified net power revenues for the fiscal year would not meet certain thresholds. Bonneville applied the 2004 SN-CRAC Rate Level Adjustment in fiscal year 2004 increasing rate levels by about ten percent over what they would have been absent the increase, although Subscription rate levels decreased slightly over fiscal year 2003 after taking into account the effects of the LB-CRAC. The rate level adjustment under the 2004 SN-CRAC Rate Level Adjustment was zero in Fiscal Year 2005 and is 1.75 percent in fiscal year 2006.

The effect of Bonneville's Subscription power rate structure for the fiscal year 2002-2006 rate period is that Bonneville's Subscription power rates have varied over time.



*Each bar represents the average full requirements rate (PF Rate) level for the indicated period. Beginning with October 2001 (the beginning of the fiscal year 2002 through 2006 rate period), the bars represent average full requirements rate (PF Rate) levels after taking account the effects of applicable LB-CRAC, FB-CRAC and SN-CRAC adjustments. The dollar figure shown above each bar is the rate level for the related period in dollars per megawatt hour. The percentage figure shown above each bar is the percentage of Base Rate levels by which the related CRAC adjusted rate levels exceeded such Base Rate levels. See "—Subscription and Related Power Rates for Fiscal Years 2002 through 2006."

Applicability of the Rate Level Adjustment Mechanisms. 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. These rate level protections expire at the end of fiscal year 2006. All other Subscription Agreement power sales (Block sales and the sale of requirements products) to Preference Customers are subject to all three rate adjustment mechanisms.

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

Bonneville's existing power rates, including the FB-CRAC, LB-CRAC, and SN-CRAC, expire at the end of fiscal year 2006 and Bonneville is in the process of proposing new power rates for the three fiscal years beginning with fiscal year 2007. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Loads and Related Contracts and Power Rates for the Period Fiscal Years 2002 through 2011—2007 Wholesale Power Rate Proceeding and Initial 2007 Power Rate Proposal." Increased market price volatility and six consecutive years of below-average runoff have significantly changed Bonneville's view of the risk and uncertainty it faces, particularly with regard to expectations of revenue from discretionary sales arising from hydroelectric generation and with respect to power purchases if necessary to meet Bonneville's power sales commitments. Bonneville also faces uncertainty regarding operational costs for fish programs in fiscal year 2006 and in the 2007 Rate Period. Bonneville believes that a rate level adjustment mechanism similar to, but more vigorous than the 2004 SN-CRAC Rate Level Adjustment, will aid in addressing cost recovery risks and ensure that Bonneville can maintain an acceptably high probability of making full and timely payment to the United States Treasury during the 2007 Rate Period.

<u>Proposal to Continue Ability to Vary Power Rate Levels</u>. A central feature of risk mitigation in the 2007 Initial Rate Proposal is the proposed reliance on a cost recovery adjustment clause ("2007 CRAC"). Under the proposed 2007 CRAC, applicable rate levels (primarily, requirements service to Preference Customers other than service under Slice of the System), for each of the three fiscal years in the 2007 Rate Period would be subject to adjustment on the basis of projected financial results for the then-current fiscal year. Near the end of a fiscal year Bonneville would produce a projection of that fiscal year's financial results. If the projection were to fall below a defined threshold, a rate level increase for the following fiscal year would take effect on October 1. Any such increase in a fiscal year's rate levels would remain in effect through September 30 of the following year. The 2007 Initial Rate Proposal includes provisions that would enable a rate level adjustment under the proposed 2007 CRAC to take effect in fiscal year 2007, depending on projected financial results for fiscal year 2006. Assuming that Bonneville were to include a rate level adjustment mechanism such as the proposed 2007 CRAC in the final power rate proposal for the 2007 Rate Period, a determination whether the proposed 2007 CRAC would be triggered in fiscal year 2007 could occur as early as August 2006.

The amount of a rate level increase, if triggered under the proposed 2007 CRAC, would be tied to the difference between (i) financial performance as reflected in a measurement of forecasted modified net power revenues, and (ii) a pre-determined annual threshold. "Modified net power revenues" are net revenues from Power Business Line operations less revenue effects arising from SFAS 133 accounting treatment and the positive net revenue effects arising from debt management activities such as Debt Optimization Program refinancings. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Bonneville's Fiscal Year 2005 Financial Results."

For purposes of determining whether the proposed 2007 CRAC would trigger in a fiscal year, Bonneville proposes to rely on a measurement of modified net power revenues as determined in the last quarter of the prior fiscal year. More precisely, Bonneville would make the determination based on a measurement of the aggregated sum of modified net power revenues since fiscal year 2000 ("Accumulated Modified Net Power Revenues" or, "AMNR"). As of the end of fiscal year 2005, AMNR were negative $393 million.

The triggering conditions for the proposed 2007 CRAC to recover additional revenues are proposed to vary by year. For the proposed 2007 CRAC to trigger in fiscal year 2007, Bonneville would have to project in August/September 2006 that AMNR as of the end of fiscal year 2006 would be lower than negative $193 million. For the proposed 2007 CRAC to trigger in fiscal year 2008, Bonneville would have to project in August/September 2007 that the AMNR as of the end of fiscal year 2007 would be below negative $36 million. For the proposed 2007 CRAC to trigger in fiscal year 2009, Bonneville would have to project in August/September 2008 that the AMNR as of the end of fiscal year 2008 would be below negative $45 million.

In most circumstances, the additional revenue to be obtained in a fiscal year under the proposed 2007 CRAC would be capped at the lower of (i) an amount estimated to recover the shortfall between the AMNR as of the end of the prior fiscal year and the 2007 CRAC threshold applicable to the year, and (ii) $300 million. (For purposes of comparison, $300 million represents about eleven percent of Bonneville's expected Power Business Line revenue requirement for fiscal year 2007.)

Thus, for example, if in August/September 2006 Bonneville were to project $205 million in modified net power revenues as of the end of fiscal year 2006, AMNR would be negative $188 million as of the end of fiscal year 2006, and the proposed 2007 CRAC would not trigger in fiscal year 2007 (negative $393 million AMNR through fiscal year

2005 plus $205 million in positive modified net power revenues projected for fiscal year 2006 equals AMNR of negative $188 million, which is $5 million higher than the fiscal year 2007 threshold of negative $193 million in AMNR). By contrast, if in August/September 2006 Bonneville were to project modified net power revenues of positive $150 million as of the end of fiscal year 2006, AMNR would be negative $243 million as of the end of fiscal year 2006. This would trigger the proposed 2007 CRAC in fiscal year 2007 and would permit Bonneville to recover an additional $50 million in such year (negative $393 million in AMNR as of the end of fiscal year 2005 plus forecasted positive modified net power revenues in fiscal year 2006 of $150 million, equals AMNR of negative $243 million for fiscal year 2006, which is $50 million below the applicable threshold for fiscal year 2007 of negative $193 million in AMNR). Stated another way, if in August/September 2006 Bonneville's projected modified net power revenues for fiscal year 2006 are less than $200 million, the 2007 CRAC would trigger and enable Bonneville to increase applicable rate levels in fiscal year 2007.

By further example, if Bonneville were to record modified net power revenues of positive $400 million in fiscal year 2006, AMNR at the end of fiscal year 2006 would be positive $7 million. If, in August/September 2007, Bonneville were to project modified net power revenues for fiscal year 2007 of negative $50 million, then Bonneville would be able to use the proposed 2007 CRAC to recover an additional $6 million in fiscal year 2008 (negative $393 million in AMNR as of the end of fiscal year 2005 plus modified net power revenues of positive $400 million in fiscal year 2006 less projected positive modified net power revenues in fiscal year 2007 of negative $50 million, equals AMNR of negative $43 million for fiscal year 2008, which is $6 million below the applicable threshold for fiscal year 2008 of negative $37 million in AMNR).

If Bonneville were to record modified net power revenues of positive $300 million in fiscal year 2006, AMNR at the end of fiscal year 2006 would be negative $93 million. If, in August/September 2007, Bonneville were to project modified net power revenues for fiscal year 2007 of positive $50 million, then Bonneville would be able to use the proposed 2007 CRAC to recover an additional $6 million in fiscal year 2008 (negative $393 million in AMNR as of the end of fiscal year 2005 plus modified net power revenues of positive $300 million in fiscal year 2006 plus projected modified net power revenues in fiscal year 2007 of positive $50 million, equals AMNR of negative $43 million for fiscal year 2008, which is $6 million below the applicable threshold for fiscal year 2008 of negative $37 million in AMNR).

Proposed Dividend Distribution Clause. The 2007 Initial Rate Proposal contains provisions that would continue a feature of the 2002 Final Power Rates, referred to as a "Dividend Distribution Clause," in which Bonneville would adjust rate levels to rebate rates if and to the extent that accumulated modified net power revenues exceed an identified target. In the 2007 Initial Power Rate Proposal that target is $800 million in end-of-fiscal-year financial reserves arising from Power Business Line operations. If such provisions were to be included in the Final 2007 Power Rate Proposal, Bonneville believes that the implementation of the 2007 Budget Proposal would reduce substantially the probability that a dividend distribution clause rebate would be triggered. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—President's Fiscal Year 2007 Budget," and "—The Effect of the President's 2007 Budget Proposal on Proposed Power Rates."

Adjustment to the Proposed 2007 CRAC to Cover Certain Fish Costs. The proposed 2007 CRAC in the 2007 Initial Rate Proposal contains provisions that would increase the permitted recoveries under the 2007 CRAC in the limited circumstances where certain fish and wildlife costs assumed in the rate proceeding are higher than expected. Under a proposed fish cost adjustment (referred to as the "NFB Adjustment"), the maximum revenues that could be recovered under the 2007 CRAC would increase if there were to be certain "financial impacts" to fish and wildlife costs arising from changes in ESA compliance. Events that would permit initiation of the NFB Adjustment are a court order, court-approved agreements, an agreement related to litigation, a new biological opinion, or other specified actions. The net financial impacts include increases in foregone power revenue, power purchases, direct program expense, operation and maintenance expense borne by the Corps or Reclamation, and capital investment.

Relationship of the 2007 Initial Power Rate Proposal to Slice of System Power Sales and to Bonneville's Obligations with Respect to the Residential Exchange. The Slice of the System power sales, which by contract are effective through fiscal year 2011, would not be subject to the proposed 2007 CRAC and the risk mitigation features inherent in the proposed base rates because Slice customers cover a proportionate share of risk of the Federal System by paying a proportionate share of the actual costs of the Federal System. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006—Preference Customer and Federal Agency Loads." While the rate for the Slice of the System product expires at the end of fiscal year 2006, the major determinants of the rate level for Slice are set by contract. Accordingly, the 2007 Initial Rate Proposal would calculate a Slice rate for the 2007 Rate Period based on actual costs of the Federal System, as is the case under the 2002 Final Power Rates.

Under the Residential Exchange Program provisions of the Northwest Power Act, Bonneville is to exchange low cost Federal System power with qualifying utilities within the Region in return for power from each such utility at its average system cost of service to meet the needs of the utility's qualifying residential and small farm customers. In reality, no power changes hands under the Residential Exchange; rather, Bonneville provides payments to the participating utilities, who then credit such payments in their billings to their qualifying small farm and residential customers, thereby lowering their power bills. The primary beneficiaries of the Residential Exchange Program are residential customers of Regional IOUs. As a general proposition, as Bonneville's cost of Residential Exchange power, as reflected in a "Residential Exchange Program Rate" set by Bonneville in its wholesale power rate proceedings, increases relative to a Regional utility's cost of service to its residential and small farm customers, Bonneville's net payment obligation under the Residential Exchange provisions of the statute may increase.

The 2007 Initial Rate Proposal includes a proposal for the Residential Exchange Program Rate even though Bonneville has no outstanding obligations under the Residential Exchange Program statute. In 2000, Bonneville and the Regional IOUs entered into Residential Exchange Settlement Agreements to settle Bonneville's obligation under the statute in lieu of reliance on the specific provisions of the statute. Subsequently, Bonneville agreed by contract to calculate the payments to Regional IOUs in the five year period beginning with fiscal year 2007 based on the difference between an independent determination of a forecast of forward market prices for power and Bonneville's PF Rate for Block sales.

The Residential Exchange Settlement Agreements are the subject of litigation. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation." Should the Residential Exchange Settlement Agreements be set aside by the court, it is possible that Bonneville's Residential Exchange obligations for the 2007 Rate Period may be established by reference to the applicable Residential Exchange Program Rate.

The 2007 Initial Rate Proposal would set the Residential Exchange Program Rate at about $69.6 per megawatt hour. By contrast, the PF Rate for Block sales under Subscription Agreements to Preference Customers is proposed to be $29.8 per megawatt hour. Under the 2007 Initial Rate Proposal, both the PF Rate for Block sales and the Residential Exchange Program Rate, to the extent it is used, would be subject to the proposed 2007 CRAC.

The Effect of the President's 2007 Budget Proposal on Proposed Power Rates. The 2007 Initial Rate Proposal was prepared prior to the issuance of the President's Budget for Fiscal Year 2007 ("2007 Budget Proposal"). The 2007 Budget Proposal proposes that for any fiscal year in which Bonneville's net secondary power sales exceed $500 million, an amount equivalent to the excess should be applied to pre-pay outstanding bonds issued by Bonneville to the United States Treasury. Bonneville currently does not expect that the 2007 Budget Proposal would affect the substance or timing of the 2007 Final Power Rate Proposal but Bonneville is planning to initiate in the summer of 2006 an additional formal rate process to implement the 2007 Budget Proposal, immediately after the 2007 Final Power Rate Proposal is effectively finalized by Bonneville. In anticipation of the additional rate process, Bonneville intends to initiate a series of customer rates workshops with its customers. Bonneville anticipates that the 2007 Budget Proposal will be implemented beginning in fiscal year 2007, the first year of the 2007 Rate Period.

While the rate level impacts of the 2007 Budget Proposal are difficult to estimate by Bonneville, Bonneville's preliminary analysis indicates that the proposal would primarily affect the probability that Bonneville would have enough positive modified net revenues in the 2007 Rate Period to activate the proposed Dividend Distribution Clause described above. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2006 Developments—President's Fiscal Year 2007 Budget."

Surplus Power Rates. With regard to rates for surplus power, the 2007 Initial Rate Proposal would continue to employ flexible rates that recover Bonneville's cost of providing such power, but at rates that enable Bonneville to participate in power markets. The amount of surplus power that Bonneville will market at such rates will depend on generation and load conditions that vary with weather, stream-flows, market conditions and numerous other factors. Unless Bonneville were to otherwise agree by contract, rates for the sale of surplus power would not be subject to the proposed 2007 CRAC.

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 such costs, including Bonneville's payments to the United

States Treasury, are made on time and in full. Depending on the exact nature of wholesale and retail transmission access, it is possible that Bonneville's power marketing function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. Nonetheless, Bonneville cannot predict with certainty its cost of power or market prices.

FERC's 1996 order, "Order 888," to promote competition in wholesale power markets established standards that a public utility under the FPA must satisfy to recover stranded wholesale power costs. The standards contain limitations and restrictions, which, if applied to Bonneville, could affect Bonneville's ability to recover stranded costs in certain circumstances. However, Bonneville's General Counsel interprets FERC Order 888 as not addressing stranded cost recovery by Bonneville under either the Northwest Power Act or sections 211/212 of the FPA. For a discussion of Order 888 and sections 211/212 of the FPA, as amended by EPA-1992, see "TRANSMISSION BUSINESS LINE—Nondiscriminatory Transmission Access and Separation of the Business Lines."

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211/212 of the FPA are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under sections 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 an order for transmission service under sections 211/212. In FERC Order 888-A, modifying original FERC Order 888, FERC addressed Bonneville's request by stating: "We clarify that our review of stranded cost recovery by [Bonneville] would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate [Bonneville] . . . and/or section 212(i), as appropriate." Therefore, it remains unclear how FERC would intend to balance Bonneville's Northwest Power Act cost recovery standards with the stranded cost rule as enunciated in FERC Order 888 in the context of FERC-ordered transmission service pursuant to sections 211/212. Contrary to the opinion of Bonneville's General Counsel, several of Bonneville's transmission customers have taken the position that transmission rates may not be set to recover stranded power costs as Bonneville envisions under the Northwest Power Act.

Under EPA-2005, FERC was granted authority to require that the rates for transmission service that Bonneville provides to itself be comparable to the rates it charges others. The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville, notwithstanding the enactment of EPA-2005. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

Changes in the Regulation of Regional Retail Power Markets

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

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

TRANSMISSION BUSINESS LINE

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately- and publicly-owned utilities, power marketers, power generators and others. Bonneville's revenues from the sale of transmission and related services accounted for roughly 16 percent of Bonneville's overall revenues in Fiscal Year 2005.

Bonneville's Transmission Business Line provides transmission service under FERC's *pro forma* Open Access Transmission Tariff. Two transmission services are offered under the Tariff: Point-to-Point and Network Integration. These services are available to all customers regardless of whether they are transmitting Federal or non-Federal power. Network Integration service is used by many Preference Customers for delivery of power purchased from Bonneville to their loads. Point-to-Point service is taken typically by marketers, independent power producers and customers that have to obtain transmission so that the generation output they have purchased can reach their service territories or agreed-to delivery points. Finally, Bonneville, as an owner of the northern portions of the Pacific Northwest-Pacific Southwest Intertie ("Intertie") and southern portions of certain transmission lines connecting areas of western Canada with the Region, provides Point-to-Point service to power marketers, including Bonneville's Power Business Line, that use Bonneville transmission service to effect power sales and related transactions inside and outside the Region.

While it is difficult to generalize as to the cost of transmission service needed to effect various power transactions, a useful point of reference may be the cost borne by certain Regional full requirements Preference Customers. These customers pay roughly $4.00 to $5.00 per megawatt hour for Network Integration transmission and ancillary services to Bonneville to provide delivery of firm power that Bonneville sells at the PF rate, which is currently priced at roughly $27 to $31 per megawatt hour, depending on type of service and exclusive of transmission. Other customers, such as marketers using Point-to-Point service to transmit non-Federal power, pay approximately $3.00 to $3.50 per megawatt hour for transmission and required ancillary services.

Bonneville's Transmission System

The Federal System includes the transmission system that is owned, operated and maintained by Bonneville as well as the Federal hydroelectric projects and certain non-Federal power resources. Bonneville's transmission system (also referred to as the "Federal transmission system") is composed of approximately 15,000 circuit miles of high voltage transmission lines, and approximately 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 percent 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, and in the south to north direction is 3675 megawatts. The rated transfer capability of the DC line in both directions is 3100 megawatts. The operating transfer capability (or reliability transfer capability) of these facilities varies by generation patterns, weather conditions, load conditions and system outages.

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

Bonneville constructed the Federal transmission system and is responsible for its operation and maintenance, and makes investments necessary to maintain the electrical stability and reliability of the system. As a matter of policy, Bonneville's transmission planning and operation decisions are guided by regional reliability practices. From time to time, Bonneville undertakes investments or reinforcements to or changes in the planning and operation of its transmission facilities to comply with the transmission system reliability criteria. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005" for a discussion of new statutory provisions relating to 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 Federal transmission system, including Bonneville's Power Business Line. To assure that Bonneville's transmission system is adequate to meet needs, Bonneville periodically reviews the system to determine whether or not to make transmission infrastructure investments. For a discussion of proposed changes in law that could affect Bonneville's use of third party sources of capital to finance such investments, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2006 Developments—President's Fiscal Year 2007 Budget."

While Bonneville has focused its transmission infrastructure efforts primarily on transmission projects needed to maintain reliability, other transmission projects are proposed that will provide additional, long-term firm transmission service for new power generation ("generation integration projects"). With regard to the financing of generation integration projects, Bonneville voluntarily applies certain pricing methodologies established by FERC. Under these methodologies, generators that interconnect with the Federal transmission system provide to Bonneville the funds necessary to meet the costs of the system upgrades required for the interconnection. The generator receives payment credits against billings by Bonneville's Transmission Business Line for transmission service Bonneville provides with respect to the generating facility. The credits are provided consistent with the FERC policy and are intended to permit the generator to recoup the amount of funds the generator provided to Bonneville.

Bonneville's current transmission system investment plan calls for Bonneville to make investments of about \$300 million a year over the four fiscal years ending September 30, 2009. To finance the foregoing investments, Bonneville expects to use a mix of United States Treasury borrowing and advance payments from transmission customers for use of the facilities being constructed. It is possible that Bonneville may also enter into capitalized lease-purchase arrangements to acquire such facilities.

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 sections 211/212 of the FPA to authorize FERC to order a "transmitting utility" to provide access to its transmission system at rates and upon terms and conditions that are just and reasonable, and not unduly discriminatory with respect to the transmitting utility's own use of its transmission system.

While Bonneville is not generally subject to the FPA, Bonneville is a "transmitting utility" under the EPA-1992 amendments to sections 211/212 of the FPA. 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 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, since 1996, Bonneville has 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 tariff to be an acceptable reciprocity tariff. The revised open access transmission tariff became effective October 1, 2001 and, as amended, remains in effect indefinitely. Bonneville continues to update the tariff as appropriate to reflect changes FERC makes to its *pro forma* open access tariff.

EPA-2005 includes provisions relating terms and conditions of transmission service that may be imposed by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services to others on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. Since 1996, Bonneville has voluntarily adopted terms and conditions for non-discriminatory open access transmission services through a FERC-filed tariff, offering transmission service to Bonneville's Power Business Line and other transmission users at the same tariff terms and conditions. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

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 1999.

Bonneville's Transmission and Ancillary Service Rates

Under the Northwest Power Act, Bonneville's transmission rates are set in accordance with sound business principles to recover the costs associated with the transmission of electric power over the Federal System transmission facilities, including amortization of the Federal investment in the Federal transmission system over a reasonable number of years, and other costs and expenses during the related 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.

In February 2005, Bonneville commenced proceedings for transmission rates and tariffs for the transmission rate period beginning October 1, 2005. Prior to the commencement of the proceedings, in January 2005, Bonneville and its transmission customers signed a 2006 transmission rate case settlement agreement. Under the agreement, Bonneville and its transmission customers agreed that Bonneville would propose to raise transmission rates on average by about 12.5 percent. In September 2005, Bonneville's proposed transmission and ancillary services rates for fiscal years 2006-2007 were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. FERC also found that Bonneville's proposed rates satisfy FERC's comparability standards applicable to non-public utilities pursuant to the reciprocity conditions of Order 888.

The rate increase was needed mainly because Transmission Business Line costs have increased somewhat due to costs of recently completed transmission facilities and because transmission sales are lower than in the recent past. Transmission customers are increasingly remarketing their transmission rights on the Federal transmission system, and there have been electric power industry-wide economic changes that have reduced the number of transmission users and the number of power transactions requiring transmission rights and access.

EPA-2005 includes provisions relating to transmission rates charged by an "unregulated transmitting utility" (a term that includes Bonneville). The provisions authorize FERC to require such utilities to provide transmission services at rates "comparable" to those the utility charges itself. Thus, FERC now has authority to require that the transmission rates Bonneville charges the Power Business Line for transmission service be comparable to the transmission rates Bonneville charges other customers. Notwithstanding FERC's new authority in this regard, Bonneville has sought and received FERC approval of transmission rates under comparability standard, and with the stricter rates standards applicable to reciprocity under Order 888, since 1996.

The foregoing provisions in EPA-2005 do not amend Bonneville's existing statutory provisions under the Northwest Power Act to establish transmission rates to recover Bonneville's transmission costs. In the opinion of General Counsel to Bonneville the foregoing EPA-2005 provisions relating to transmission rates would not adversely affect Bonneville's authority and obligation to fully recover the costs of providing transmission service through its transmission rates. See

"DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

Bonneville's Participation in a Regional Transmission Organization

In January 2000, FERC issued a final rule on regional transmission organizations ("RTOs"), establishing minimum characteristics and functions for an RTO and requiring that each jurisdictional utility (a term that does not include Bonneville) make certain filings regarding the formation of and participation in an RTO.

Between early 2000 and 2002, jurisdictional Regional transmission owners and Bonneville developed a proposal for a Northwest RTO, to be named RTO West, and made various filings with FERC. FERC approved significant portions of the proposal in orders issued in April 2001 and September 2002.

After attempting to resolve remaining issues among themselves with regard to RTO West and determining that additional Regional support was necessary, the transmission owners, including Bonneville, in Spring 2003 resumed their engagement with Regional stakeholders to develop a more broadly supported RTO proposal. This process generated a proposal in late 2003 for an independent transmission entity that would begin with a more limited scope of operation than had been proposed for RTO West and that would be subject to increased member control.

In December 2004, Bonneville and eight other entities owning transmission facilities in the northwestern United States and in British Columbia voted to adopt bylaws for a new RTO named Grid West. In April 2005, Bonneville and other utilities filed a request for declaratory judgment with FERC seeking clarification on a number of regulatory and jurisdictional issues related to the developing Grid West proposal and in June 2005 FERC responded favorably on all issues. Among other things, it was proposed that Grid West would operate a real time market for ancillary and related transmission service, engage in system-wide transmission planning, coordinate transmission outages, calculate available transmission capacity and facilitate the resale of unused available transmission capacity.

In October 2005, after discussion with utilities and customers in the Northwest, Bonneville proposed additional changes to the Grid West bylaws to increase Grid West's accountability to the Region and to advance the implementation date of certain functions that Bonneville wanted to have implemented in the near term. A majority of the other transmission owning utilities involved in the development of Grid West proposal found Bonneville's proposals to be unacceptable and established a policy that only funding entities would participate on the Grid West board. As a consequence, Bonneville resigned from the Grid West board. Bonneville is currently pursuing an approach to implement its proposal (referred to as Columbia Grid), with, initially, a smaller set of transmission owners. Notwithstanding its resignation from Grid West, Bonneville has agreed to participate in the Grid West process. Bonneville is unable to predict whether the Grid West proposal will succeed without Bonneville or whether an alternative will be developed.

In February 2005, Public Utility District No. 1 of Snohomish County, Washington, a large Preference Customer, filed a petition in the Ninth Circuit Court challenging Bonneville's authority to (i) fund the development of Grid West, (ii) sub-delegate its authorities to Grid West, and (iii) terminate its development of an environmental impact statement relating to the development of certain transmission service policies. In view of Bonneville's resignation from Grid West, Bonneville is planning to file a motion to dismiss this litigation.

The 2005 Energy Act includes provisions explicitly authorizing Bonneville to participate in the formation and operation of an RTO. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

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 under the Northwest Power Act 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.

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 power rates, FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a power 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 power 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.

For a discussion of FERC rate review and regulations related to transmission access and rates, see "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines" and "TRANSMISSION BUSINESS LINE—Bonneville's Transmission and Ancillary Service Rates."

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 Preference and certain Federal agency customers; (2) to DSIs; and (3) for those portions of loads 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—Residential Exchange Program." The rates for power sold to these respective customer classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

Other Firm Power Rates

Bonneville's rates for other firm power sales within the Region are based on the cost of such resources as Bonneville 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.

Surplus Energy

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

Limitations on Suits Against Bonneville

Suits challenging Bonneville's actions or inaction may only be brought pursuant to certain Federal statutes that waive sovereign immunity. These statutes limit the types of actions, remedies available, procedures to be followed and the proper forum. In the opinion of Bonneville's General Counsel, the exclusive remedy available for a breach of contract by Bonneville is a judgment for money damages. See "BONNEVILLE LITIGATION" for information regarding pending litigation seeking to compel or restrain action by Bonneville.

Laws Relating to Environmental Protection

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 two such sites. One site is a Bonneville-operated facility awaiting determination by the EPA. The other is a non-Bonneville site 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 total between $1 million and $2 million 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 a Canadian counterpart, the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River basin for the purposes of power generation and flood control.

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 specified point unless the United States Entity and the Canadian Entity agree to other arrangements. The United States Entity and Canadian Entity reached such an agreement in the late 1990s, and as a result the United States Entity does not have to build a transmission line to assure delivery to the point referred to in the Treaty.

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 specified point 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 a form of regulatory oversight comparable to that currently applicable to privately-owned transmission and subjecting Bonneville's transmission operations and assets to FERC regulation. Under this type of regulation, in general, a transmission owner may not use its transmission system to recover costs of its power function. This type of regulation would be at odds with Bonneville's General Counsel's legal opinion of Bonneville's current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in Congress have included privatizing the Federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at Federal hydroelectric projects, studying the removal of certain federally-owned dams of the Federal System, and requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates. None of these bills or proposals was enacted into law.

In 2005, Congress enacted new legislation altering FERC's review over Bonneville's operations. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Energy Policy Act of 2005."

Bonneville cannot predict whether these or any other proposals relating to it will be enacted or implemented. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such future proposals, if enacted or implemented, could affect Bonneville's ability to perform its obligations with respect to the Series 2006 Bonds.

Bonneville is a Federal agency. It is subject to direction or guidance in a number of respects from the United States Office of Management and Budget, DOE, FERC, the United States Treasury and other Federal agencies. Bonneville is frequently the subject of, or would otherwise be affected by, various executive and administrative proposals. Bonneville is unable to predict the content of future proposals; however, it is possible that such proposals could materially affect Bonneville's operations and financial condition.

For proposals relating to Bonneville in the President's Fiscal Year 2007 Budget, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2006 Developments—President's Fiscal Year 2007 Budget."

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

Prior to 1974, Congress annually appropriated funds for the payment of Bonneville's obligations, including working capital expenditures. Under the Transmission System Act, Congress created the Bonneville Fund, a continuing appropriation available to meet all of Bonneville's cash obligations.

All receipts, collections and recoveries of Bonneville in cash from all sources are now deposited in the Bonneville Fund. These include revenues from the sale of power and other services, trust funds, proceeds from the sale of bonds by Bonneville to the United States Treasury, any appropriations by Congress for the Bonneville Fund, and any other Bonneville cash receipts.

Bonneville is authorized to make expenditures from the Bonneville Fund without further appropriation and without fiscal year limitation if such expenditures have been included in Bonneville's annual budget to Congress. However, Bonneville's expenditures from the Bonneville Fund are subject to such directives or limitations as may be included in an appropriations act. Bonneville's annual budgets are reviewed and may be changed by the DOE and subsequently by the United States Office of Management and Budget. The Office of Management and Budget, after providing opportunity for Bonneville to respond to proposed changes, includes Bonneville's budget in the President's budget submitted to Congress.

The existence of the Bonneville Fund also enables Bonneville to enter into contractual obligations requiring cash payments that exceed, at the time the obligation is created, the sum of the amount of cash in the Bonneville Fund and available borrowing authority. Pursuant to the Project Act and other law, Bonneville has broad authority to enter into contracts and make expenditures to accomplish its objectives.

No prior budget submittal, appropriation, or any prior Congressional action is required to create such obligations except in certain specified instances. These include construction of transmission facilities outside the 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 certain major generating or conservation resources.

The Federal System Investment

The total cost of the multipurpose Corps and Reclamation projects that are part of the Federal System is allocated among the purposes served by the projects, which may include flood control, navigation, irrigation, municipal and industrial water supply, recreation, the protection, mitigation and enhancement of fish and wildlife, and the generation of power. The costs allocated to power generation from the Corps and Reclamation projects as well as the cost of the transmission system prior to 1974 have been funded through appropriations. The capital costs of the transmission system since 1974 and certain capital conservation and fish and wildlife costs since 1980 have been funded in great part through the use of Bonneville's borrowing authority with the United States Treasury.

Bonneville is required by statute to establish rates that are sufficient to repay 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, 2005, Bonneville had repaid $6.8 billion of principal of the Federal System investment and has $4.3 billion principal amount outstanding with regard to such appropriated investments.

Bonneville Borrowing Authority

Bonneville is authorized to issue and sell to the Secretary of Treasury, and to have outstanding at any one time, up to $4.45 billion aggregate principal amount of bonds. Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.78 billion of bonds were outstanding as of September 30, 2005. Under current law, none of this borrowing authority may be used to acquire electric power from a generating facility having a planned capability of more than 50 average megawatts. Of the $4.45 billion in United States Treasury borrowing authority, $1.25 billion is available for renewable resources and conservation purposes and $3.2 billion is available for Bonneville's transmission capital program and to implement Bonneville's authorities under the Northwest Power Act.

The interest on Bonneville's outstanding bonds is set at rates comparable to rates on debt issued by other comparable Federal Government institutions at the time of issuance. As of September 30, 2005, the interest rates on the outstanding bonds ranged from 2.30 percent to 8.55 percent with a weighted average interest rate of approximately 4.76 percent. The original terms of the outstanding bonds vary from 3 to 40 years. The term of the bonds is limited by the average expected service life of the associated investment: 40 years for transmission facilities, 75 years for Corps and Reclamation capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. Bonds can be issued with call options. As of September 30, 2005, Bonneville had seven callable bonds on its books totaling $353.9 million.

Debt Optimization Program

In the spring of 2000, Bonneville presented a "Debt Optimization Program" to Energy Northwest. Said Program, which was agreed to by Energy Northwest, involves the extension of the final maturity of debt issued for the Columbia Generating Station. In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan in which it also incorporated an increase in the average life of outstanding bonds issued for Projects 1 and 3 as a refinancing program objective. In addition, in early 2006 Energy Northwest and Bonneville agreed that certain bonds to be issued to finance new investments at the Columbia Generating Station, and certain new Columbia Generating Station refunding bonds, may have maturities through 2024. A portion of such refunding bonds will be issued in connection with the Debt Optimization Program.

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 Debt Optimization Program 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. Under the Debt Optimization Program through July 1, 2005, approximately $1.8 billion in maturing bonds issued by Energy Northwest for the Net Billed Projects have been refinanced with new bonds having final maturities in calendar years 2013-2018. Bonneville expects that Energy Northwest will continue to undertake similar refundings through at least fiscal year 2008. See "PURPOSE OF ISSUANCE—Refunding Program" in the Official Statement.

Order in Which Bonneville's Costs Are Met

Bonneville's operating revenues include amounts equal to net billing credits provided by Bonneville under the Net Billing Agreements, as described in the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing Agreements." Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Net Billing Agreements for the Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. (Bonneville and Energy Northwest are proposing to enter into agreements that would obligate Bonneville to pay the costs of the Net Billed Projects on a current cash basis. See "—Proposed Direct Pay Agreements.")

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 Reclamation 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 2005 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.088 billion in Fiscal Year 2005, approximately $307 million was for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury and approximately $6 million was for the amortization ahead of schedule of Federal appropriated investment repayment responsibilities. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Program through the use of cash flows derived from reduced debt service in such fiscal year for the Project 1, Project 3 and the Columbia Generating Station. Such United States Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. In accordance with the Debt Optimization Program, Bonneville plans to make similar advance amortization payments to the United States Treasury in fiscal year 2006 and in subsequent fiscal years. See "—Debt Optimization Program."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all non-United States Treasury cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2006 Bonds, payments, if any, under the 1989 Letter Agreement and the proposed Direct Pay Agreements, and other operating and maintenance expenses have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments under the Net Billing Agreements securing the Series 2006 Bonds, payments, if any, under the 1989 Letter Agreement and the proposed Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS—1989 Letter Agreement" and "—Proposed Direct Pay Agreements" and see "—Proposed Direct Pay Agreements" in this Appendix A.

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 with Net Billing Agreement Participants ("Participants") requiring net billing to fund resource acquisitions or other capital program investments. For a description of the Net Billing Agreements, net billing and Participants, see the Official Statement under "SECURITY FOR THE NET BILLED BONDS."

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 may 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.

Proposed Direct Pay Agreements

As part of the preparatory work leading to the 2007 Initial Power Rate Proposal, Bonneville and Regional power customers explored various proposals to reduce the rate proposal while maintaining an acceptably high probability that Bonneville will meet its United States Treasury payment obligations on time and in full during the 2007 Rate Period. Discussions focused on finding means to assure that Bonneville's cash receipts and payments are more efficiently matched so that Bonneville may reduce the cash balance it carries in the Bonneville Fund to assure full and timely payment of its obligations, both Federal and non-Federal. As a result of the foregoing discussions, Bonneville and Energy Northwest have proposed to enter into certain Direct Pay Agreements. Under these proposed agreements, Bonneville would commit contractually to pay directly to Energy Northwest the costs of Columbia Generating Station, Project 1 and Project 3 as billed to Bonneville by Energy Northwest.

In reliance on Bonneville's proposed Direct Pay Agreement obligations, the billing statements that Energy Northwest is required to provide to Participants under the Net Billing Agreements would show the expected payments from Bonneville under the proposed Direct Pay Agreements as amounts payable from sources other than the Net Billing Agreements. See the Official Statement under "SECURITY FOR THE NET BILLED BONDS—Net Billing and Related Agreements—Payment Procedures." Thus, the amounts to be paid by Participants to Energy Northwest in a Net Billing Agreement Contract Year would be reduced to zero, thereby reducing Bonneville's obligation to provide net billing credits to zero as well. In this manner, Bonneville would meet Net Billed Project costs on a current basis by means of cash payments from the Bonneville Fund.

By reducing the amount of net billing credits, Bonneville would receive more revenues in cash from Participants during times of the year when Bonneville would otherwise carry its lowest annual cash balances, typically after Bonneville makes its end-of-fiscal-year payments to the United States Treasury. Under the proposed Direct Pay Agreements, Energy Northwest's revenues with respect to the Net Billed Projects would be received throughout the year rather than predominantly in the early months of Energy Northwest's fiscal year (July 1 – June 30), as is currently the case. Bonneville estimates that, as a consequence of re-shaping its annual cash flow patterns under the proposed Direct Pay Agreements, Bonneville could lower its 2007 Final Power Rate Proposal by between five percent and ten percent from what such proposal would otherwise be.

The Direct Pay Agreements would not result in the amendment or termination of the Net Billing Agreements or any other agreements of Bonneville with respect to the Columbia Generating Station, Project 1 or Project 3, including the 1989 Letter Agreement, the Voluntary Cash Payment Agreements and the Assignment Agreements, each as described in the Official Statement under "SECURITY FOR THE NET BILLED BONDS." The Participants' obligations to pay for power purchased from Bonneville would not change as a result of the Direct Pay Agreements. The effect of the proposed agreements would be that the Participants would no longer pay such amounts to Energy Northwest (with resulting net billing credits from Bonneville) for the period that proposed Direct Pay Agreements remain in effect. Rather, the Participants would pay their billings by Bonneville for power and transmission services to Bonneville. The Direct Pay Agreements would provide that, in the event that Bonneville were to fail to make required payments under the proposed Direct Pay Agreements, Energy Northwest would re-initiate net billing as required under the Net Billing Agreements.

While the payments to Energy Northwest under the proposed Direct Pay Agreements would be included under the respective pledge of revenues for related series of Net Billed Bonds, it is proposed that such agreements would not be pledged to the payment of the related series of Net Billed Bonds and would be subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

Bonneville expects to enter into the proposed Direct Pay Agreements with Energy Northwest before the end of April 2006.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for the Corps, Reclamation, and the Fish and Wildlife Service in Fiscal Year 2005 were $142 million, $52 million, and $18 million, respectively.

Bonneville believes that, in contrast to prior practice, the direct funding 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 is necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-Federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct funding would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct funding could be made to the exclusion of non-Federal payments that would otherwise have been paid under historical practice. A result of any direct funding obligation by Bonneville is that there has been and will be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, during the terms of the direct funding agreements, Bonneville expects to have roughly $400 million to $800 million in scheduled payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses.

Within Fiscal Year Prepayments of Appropriations Repayment Obligations

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

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

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

In the second quarter of fiscal year 2004, Bonneville prepaid by about eight months approximately $73 million principal amount of appropriations repayment obligations that were due at the end of that fiscal year. Prior to making the above-mentioned prepayment, Bonneville concluded that it had in excess of a 99 percent probability of making its full scheduled fiscal year 2004 payments to the United States Treasury and a slightly greater probability of making the subject appropriations repayment obligations in full in fiscal year 2004, after taking into account the interest savings to be achieved through early payment. Bonneville did not make any such early appropriations repayments in fiscal year 2005 and is not planning to make such prepayments in fiscal year 2006.

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

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

Position Management 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 price, electricity price volatility, stream-flow uncertainty, interest rate, and contractual risks affects the quantity and quality of Bonneville's cash flow and income.

Bonneville seeks to ensure that its management of various financial risks be conducted in a controlled, business-like manner. To this end, Bonneville has adopted risk management policies and organizational structures that systematically address the management of these activities. Policies governing transacting are overseen by Bonneville's Transacting Risk Management Committee ("TRMC"), which is comprised of senior Bonneville executives.

Bonneville's policies allow the use of financial instruments such as commodity and interest rate futures, forwards, options and swaps to manage Bonneville's net revenue outcomes. Such policies do not authorize the use of financial instruments for purposes outside TRMC-established strategies. Strategies are established in the context of portfolio management, as opposed to individual position/exposure management, and are subject to quantitatively derived hard position limits mathematically linked to Bonneville's financial metrics, such as United States Treasury payment probability. Exceptions to established policies must be cleared by the TRMC before execution.

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

Historical Federal System Financial Data

Federal System historical financial data for fiscal years 2003 through 2005 are hereinafter set forth in the "Federal System Statement of Revenues and Expenses." This information has been derived from the annual audited financial statements of the Federal System and should be read in conjunction with Appendix B-1. Federal System financial statements are prepared in conformity with generally accepted accounting principles. The audited Financial Statements of the Federal System (which include accounts of Bonneville as well as those of the generating facilities of the Corps and Reclamation for which Bonneville is the power marketing agency) for the Fiscal Year 2005 are included as Appendix B-1 to the Official Statement. The unaudited quarterly financial report for the three months ended December 31, 2005 is included as Appendix B-2.

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

Fiscal year ending September 30,	2005	2004	2003
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-owned utilities (1)	$ 1,717,063	$ 1,737,895	$ 1,723,341
Direct Service Industrial Customers	82,454	92,424	18,494
Northwest Investor-Owned Utilities	390,511	363,201	436,702
Sales outside the Northwest Region (2)	600,765	489,063	628,243
Book-outs (3)	(238,847)	(212,155)	0
Total Sales of Electric Power	2,551,946	2,470,428	2,806,780
Transmission (4)	527,383	535,936	552,718
Fish Credits and other revenues (5)	188,754	191,547	252,606
Total Operating Revenues	3,268,083	3,197,911	3,612,104
Operating Expenses:			
Bonneville O&M (6)	614,716	613,121	607,616
Purchased Power (3)	580,213	582,129	1,043,009
Corps, Reclamation and Fish & Wildlife O&M (7)	215,533	214,035	198,539
Non-Federal entities O&M — net billed (8)	241,703	221,210	208,535
Non-Federal entities O&M — non-net billed (9)	40,551	37,521	39,864
Total Operation and Maintenance	1,692,716	1,668,016	2,097,563
Net billed debt service	267,373	222,779	104,329
Non-net billed debt service	24,167	25,696	15,205
Non-Federal Projects Debt Service (10)	291,540	248,475	119,534
Federal Projects Depreciation	375,600	366,239	350,025
Residential Exchange (11)	144,073	125,915	143,967
Total Operating Expenses	2,503,929	2,408,645	2,711,089
Net Operating Revenues	764,154	789,266	901,015
Interest Expense:			
Appropriated Funds	257,015	281,607	280,094
Long-term debt	102,077	110,251	166,598
Capitalization Adjustment (12)	(64,905)	(68,566)	(67,703)
Allowance for funds used during construction	(16,903)	(38,441)	(33,398)
Net Interest Expense	277,284	284,851	345,591
Net Revenues/(Expenses)	$ 486,870	$ 504,415	$ 555,424
Total Sales (unaudited) — average megawatts (Net of Residential Exchange Program)	10,288	9,772	10,764

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

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

(3) Total Operating Expenses and Revenue from Electricity Sales reflect accounting guidance from the Emerging Issues Task Force ("EITF") of the Financial Accounting Standards Board ("FASB"). Under this guidance ("EITF 03-11"), which was applied by Bonneville for the first time as of fiscal year 2004, both revenues and expenses associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) are to be reported on a "net" basis in both operating revenues and purchased power expense. Formerly, such book-outs were to be reported on a "gross" basis. Application of the then recently issued guidance thus decreased both operating revenues and purchase power expense by $212 million in fiscal year 2004 and by $239 million in Fiscal Year 2005 but had no effect on the net revenue, cash flows or margins.

(4) Bonneville obtains revenues from the provision of transmission and other related services.

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife credits Bonneville receives in its United States Treasury repayment obligation. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. In addition, under FASB Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville reported unrealized mark-to-market gains of $55.3 million, $89.4 million and $94.6 million in fiscal years 2003, 2004 and 2005, respectively. 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 change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. It is Bonneville's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended. 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 not required to be recorded at fair value in the financial statements. For all other derivative transactions Bonneville applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. Bonneville does not apply hedge accounting.

(6) 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.

(7) Corps, Reclamation and Fish & Wildlife operations and maintenance expenses include the costs of the Corps and Reclamation generating projects and expenses of the Fish and Wildlife Service, in connection with the Federal System.

(8) The Non-Federal entities O&M – net billed expense includes the operation and maintenance costs for generating facilities, the generating capability or output of which Bonneville has agreed to purchase under certain capitalized contracts, the costs of which are net billed, including Energy Northwest's Project 1, Project 3, and Columbia Generating Station.

(9) The Non-Federal entities O&M – non-net billed expense includes the operation and maintenance costs for generating facilities, and the generating capability or output of which Bonneville has agreed to purchase under certain capitalized contracts, the costs of which are not net billed.

(10) These amounts include payment by Bonneville for all or a part of the generating capability of, and the related 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 Eugene Water and Electric Board's ("EWEB") 30 percent ownership share of the Trojan Nuclear Project. These amounts also include payment by Bonneville with respect to several small generating and conservation projects.

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

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

Management Discussion of Operating Results

Fiscal Year 2005

In Fiscal Year 2005, total operating revenues were $3.268 billion, an increase of $70 million, or two percent, from the fiscal year ended September 30, 2004 ("fiscal year 2004"). Sales from electricity and transmission sales for the fiscal year increased approximately $78 million, or three percent, from levels in fiscal year 2004. The increased sales from electricity and transmission sales resulted from higher discretionary sales of surplus power outside the Region. The Statement of Financial Accounting Standards 133, "Accounting for Derivative Instrument and Hedging Activities," ("SFAS 133") derivative mark-to-market amount increased $5 million, or six percent, miscellaneous revenues increased $6 million, or ten percent, and United States Treasury credits for fish under Northwest Power Act section 4(h)(10)(C) ("4(h)(10)(C) Credits") decreased $19 million, or 25 percent, in Fiscal Year 2005 when compared to the prior fiscal year. For a description of 4(h)(10)(C), 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."

In total, operating expenses increased $95 million, or four percent, in Fiscal Year 2005 when compared to the prior fiscal year. Operations and maintenance increased $45 million, or four percent, from fiscal year 2004. This increase reflects the effects of higher operating costs at Columbia Generating Station of $21 million, mainly for nuclear fuel, and increased payments to Regional IOUs relating to the Residential Exchange Program of $18 million. Operating expenses in Fiscal Year 2005 also reflect that purchase power decreased $2 million, or less than one percent, and that Non-Federal Projects Debt Service expense increased $43 million, or 17 percent, in each case when compared to the prior fiscal year. The Non-Federal Project Debt Service expense increased in part because, in contrast to fiscal year 2004, Energy Northwest did not have debt service reserve funds becoming available to pay debt service. Bonneville's fiscal year 2004 financial reports reflected the consequences of a one-time-only amount of $79 million that was made available to pay related debt service when reserve funds for certain Net Billed Bonds were replaced with surety agreements by Energy Northwest. The surety agreements thus effected a reduction in Bonneville's fiscal year 2004 Non-Federal Projects Debt Service that did not occur in Fiscal Year 2005.

In addition, Federal Projects Depreciation increased $9 million, or three percent, primarily due to the commencement of operation of the Grand Coulee-Bell transmission line. Net interest expense for Fiscal Year 2005 decreased $8 million, or three percent, compared to the prior year. Interest on appropriated funds decreased due to lower principal owed to the United States Treasury. Interest on bonds issued to the United States Treasury decreased as the weighted average interest rate declined from 5.3 percent at the beginning of fiscal year 2004 to 4.9 percent at the beginning of Fiscal Year 2005. This interest expense also decreased as the income earned on Bonneville's cash account at the United States Treasury increased with higher average cash balances. Bonneville reports interest expense on long-term debt net of the interest income earned. The decrease in interest expense was partially offset by decreased allowance for funds used during construction due to lower construction work in progress balances.

Net revenues were $487 million in Fiscal Year 2005, a decrease of $18 million, or four percent, from fiscal year 2004 as a result of the factors discussed above. However, modified net revenues (*i.e.*, net revenues after adjusting for the effects of the Debt Optimization Program, other non-Federal debt activities and accounting treatment under SFAS 133) were approximately $126 million. For further information on Fiscal Year 2005 financial results, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Bonneville's Fiscal Year 2005 Financial Results."

Fiscal Year 2004

Bonneville had net revenues of $504 million in fiscal year 2004, a decrease of approximately $51 million, or nine percent, from the fiscal year ended September 30, 2003 ("fiscal year 2003"). The Debt Optimization Program and other non-Federal debt management actions contributed significantly to sustaining positive net revenues. After adjusting for the positive net revenue effects of that Program and of the unrealized mark-to-market gains arising from the accounting treatment of certain transactions under SFAS 133, Bonneville had modified net revenues of $66 million in fiscal year 2004. Under SFAS 133, Bonneville reported an unrealized gain of $89.4 million, reflecting the difference between the mark-to-market value and the contracted price of certain derivatives not designated as hedging instruments.

With respect to power marketing, in fiscal year 2004, Bonneville's total operating expenses and revenues from electricity sales reflected for the first time the impacts of certain then newly adopted accounting guidance from the Emerging Issues Task Force ("EITF") of the FASB. Under this new guidance (referred to herein as "EITF Issue No. 03-11"), which Bonneville adopted as of October 1, 2003, both revenues and expenses associated with non-trading energy activities that are "booked out" (settled other than by the physical delivery of power) are to be reported on a "net" basis in both operating revenues and purchased power expense. Formerly, such book-outs were to be treated on a "gross" basis. Application of the new guidance thus decreased both operating revenues from power sales and purchase power expense in fiscal year 2004 by $212 million from what they otherwise would have been absent application of the guidance. The accounting treatment under EITF Issue No. 03-11 had no effect on net revenue, cash flows or margins. Prospective application of EITF Issue No. 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts when compared with financial statements issued prior to the application of the guidance.

Total operating revenues in fiscal year 2004 when compared to fiscal year 2003 decreased by $414 million, or eleven percent, due to lower total power sales, reduced 4(h)(10)(C) credits, and a comparatively lower LB-CRAC percentage for the six month period beginning April 1, 2004. Total operating revenues were also affected by the application of EITF Issue No. 03-11, as discussed above.

The decrease in total power sales was largely caused by a decrease in power sales to Regional IOUs of $74 million, a 17 percent decrease, and decreased sales outside the Region of $139 million, a 22 percent decrease. Total power sales in fiscal year 2004 were lower when compared to fiscal year 2003, despite increased sales to Preference Customers and Federal agencies of $15 million, or a one percent increase, and to DSI customers of $74 million, or a 400 percent increase. Power sales revenues and purchase power expense both declined substantially when compared to audited fiscal year 2003 results, notwithstanding that runoff conditions in both years were comparably below average. Revenue from power sales declined by $355 million in fiscal year 2004 when compared to fiscal year 2003. Much of the decline in such sales occurred because certain power purchases (including Augmentation Agreement purchases) by Bonneville had either been fulfilled or restructured, thereby resulting in substantially reduced amounts of power available to Bonneville for sale. As noted below, these contract expirations and restructurings also reduced purchase power expense. As described above, application of new accounting guidance decreased reported revenues.

Fish and wildlife credits, which are accounted as a component of total sales, decreased from $175 million in fiscal year 2003 to $77 million in fiscal year 2004 in part due to fully depleting the Fish Cost Contingency Fund in fiscal year 2003. Fish and wildlife credits in fiscal year 2003 included $97 million in 4(h)(10)(C) credits and $78 million in credits from the Fish Cost Contingency Fund. The Fish Cost Contingency Fund was an amount of accumulated but unused monetary credits under section 4(h)(10)(C) which had been earned by Bonneville prior to fiscal year 1995. Under prior policy agreement among Federal agencies, those credits were to be used by Bonneville as credits to its United States Treasury payments under limited circumstances, including low water conditions. Low water conditions in fiscal year 2003 led to the use in that year of the remaining amounts of credits in the Fish Cost Contingency Fund and it is now fully and finally depleted. Notwithstanding the depletion of the Fish Cost Contingency Fund, Bonneville continues to accrue and use 4(h)(10(C) credits on an annual basis. Also, in fiscal year 2004, Bonneville received lower non-firm transmission revenues reflecting changes by customers in their transmission purchase and sales practices (i) as they purchased more transmission rights in the secondary market and less from Bonneville, and (ii) as the total volume of power transactions using Bonneville transmission system declined.

Total Operating Expenses in fiscal year 2004 were approximately $302 million lower when compared to fiscal year 2003, a decrease of about 11 percent, largely due to decreased Purchase Power in fiscal year 2004. Purchase Power decreased by $461 million, or by about 44 percent, as a result of the expiration of Purchase Power commitments of nearly 400 average megawatts. Total operating expenses were also affected by the application of EITF Issue No. 03-11, as discussed above.

Non-Federal Projects Debt Service increased $129 million, or 108 percent, primarily because fiscal year 2003 amortization of debt for Energy Northwest Net Billed Projects was comparatively low as a result of the Debt Optimization Program and the embedded amortization schedule for such debt. In addition, in fiscal year 2003 Energy Northwest debt service was paid in part by funds made available when reserve funds for certain Energy Northwest Net Billed Bonds were replaced with surety agreements. Operations and maintenance increased $13 million and Federal Projects Depreciation Expense increased $16 million. Net interest expense on United States Treasury repayment obligation declined $61 million compared to fiscal year 2003 due to early amortization of some of such debt under the Debt Optimization Program and to the generally lower interest rates on borrowings by Bonneville from the United States Treasury to finance Federal System generating and transmission projects.

Fiscal Year 2003

Bonneville had net revenues of $555 million in fiscal year 2003, an increase of approximately $546 million over fiscal year 2002. However, after adjusting for the effects of the implementation of the Debt Optimization Program and other debt management actions and the effects of SFAS 133, modified net revenues were $37 million in fiscal year 2003. Total operating revenues in fiscal year 2003 increased by $78 million, or two percent, from the previous fiscal year because of greater sales to Regional IOUs and increased 4(h)(10)(C) credits, even though there were both reduced hydro generation and reduced power sales when compared to fiscal year 2002. However, the average price for discretionary surplus power sales rose from $26 per megawatt hour to $37 per megawatt hour, an increase of 42 percent. Total fish and wildlife credits, including credits from the Fish Cost Contingency Fund and 4(h)(10)(C) credits, increased from $38 million to $175 million in fiscal year 2003. See "—Fiscal Year 2004" for a description of the Fish Cost Contingency Fund." Such credits increased due to below-average water conditions and increased power purchases that resulted from reduced hydro supply.

Total Operating Expenses in fiscal year 2003 were approximately $461 million lower as compared to the year ended September 30, 2002 ("fiscal year 2002"), a decrease of about 15 percent. This was largely due to decreased Non-Federal Projects Debt Service, which decreased by $111 million, or 48 percent, because of the deferral of some principal payments due in fiscal year 2003 into the future, primarily as a result of continued implementation of the Debt Optimization Program. Lower interest rates through refinancing some of the non-Federal debt also contributed to the decline in debt service. Net Interest Expense on Federal debt declined by $7 million compared to fiscal year 2002 due to generally lower interest rates on borrowings from the United States Treasury to finance Federal generating and transmission projects. Total Operations and Maintenance costs, excluding Purchased Power, also decreased by $121 million, or about nine percent, from the previous year. Lower bad debt expense and general and administrative expense were the main factors that led to this decrease. Purchased Power also decreased by $244 million, or 19 percent, in view of comparatively lower prices for the power purchased by Bonneville and the release of Bonneville from certain power purchase commitments as the result of a settlement between Bonneville and Enron Power Marketing Corp. in its bankruptcy proceedings.

Statement of Non-Federal Project Debt Service Coverage

The Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments uses the Federal System Statement of Revenue and Expenses to develop a non-Federal project debt service coverage ratio ("Non-Federal Project Debt Service Coverage Ratio"), which demonstrates how many times total non-Federal project debt service is covered by net funds available for non-Federal project debt service. Net funds available for non-Federal project debt service is defined as total operating revenues less operating expenses (see footnote 9 to the "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments," 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 Federal System Operations and Maintenance Expense."

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

Fiscal Years ending September 30,	2005	2004	2003
Total Operating Revenues	$ 3,268,083	$3,197,911	$3,612,104
Less: Operating Expense(1)	1,621,256	1,579,896	2,042,991
Net Funds Available for Non-Federal Project Debt Service	1,646,827	1,618,015	1,569,113
Less: Total Non-Federal Project Debt Service(2)	291,540	248,475	119,534
Revenue Available for Treasury	1,355,287	1,369,540	1,449,579
Amount Paid to Treasury:			
Corps and Reclamation O&M(3)	215,533	214,035	198,539
Net Interest Expense(4)	277,284	284,851	345,591
Capitalization Adjustment(5)	64,905	68,566	67,703
Allowance for Funds Used During Construction(4) (6)	13,329	21,584	18,641
Amortization of Principal	616,502	592,500	543,747
Total Amount Allocated for Payment to Treasury(7)	1,187,553	1,181,536	1,174,221
Revenues Available for Other Purposes(8)	167,734	188,004	275,358
Non-Federal Project Debt Service Coverage Ratio(9)	5.6	6.5	13.1
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio(10)	1.7	1.7	1.7

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

(2) Includes net billed and non-net billed debt service. Non-net billed debt service amounted to \$24.2 million, \$25.7 million and \$15.2 million for fiscal years 2003, 2004 and 2005, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Reclamation and Fish & Wildlife for fiscal years 2003, 2004 and 2005. 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 2003, 2004, and 2005 were \$1.057 billion, \$1.053 billion and \$1.088 billion, respectively, and include the amounts for each such year for direct funding for the Corps, Reclamation and Fish & Wildlife as portrayed under "Corps and Reclamation O&M." 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 \$188 million at the end of fiscal year 2002 (not depicted) and \$554 million at the end of Fiscal Year 2005.

(9) The "Non-Federal Project 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 Project 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 (unaudited)[1]
(Actual Dollars in Thousands)

Fiscal years ending September 30,	2005	2004	2003
Operating Revenues from Publicly-Owned Utilities[2]	\$ 1,717,063	\$ 1,737,895	\$ 1,723,341
Net Billing Obligations:			
Net Billing Credits	518,605	508,618	476,947
Payments in Lieu of Net Billing[3]	(23,528)	(21,395)	(140,261)
Net Billing Obligations — Cash	495,077	487,327	336,686
Net Billing Expenditures:			
Net Billed Debt Service	267,787	222,779	104,329
Other Entities O&M — Net Billed	241,703	221,210	208,535
Increase/(Decrease) in Prepaid Expense	-14,413	43,338	23,822
Net Billing Expenditures — Accrual	\$ 495,077	\$ 487,223	\$ 336,686

(1) Bonneville funds its obligation for the Energy Northwest Net Billed Projects and the Eugene Water and Electric Board's ("EWEB") 30 percent ownership share of the Trojan Nuclear Project (which is also net billed) on a cash basis and it expenses the related 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. Bonneville and Energy Northwest propose to enter into certain agreements under which Bonneville would fund the costs of Energy Northwest's Net Billed Projects on a cash payment basis. See "—Proposed Direct Pay Agreements."

(2) Bonneville's actual revenues from Publicly-Owned Utilities exceeded net billing obligations. Most Publicly-Owned Utilities are Participants in the net billed projects. Bonneville and Energy Northwest propose to enter into certain agreements under which Bonneville would fund the costs of Energy Northwest's Net Billed Projects on a cash payment basis. See "—Proposed Direct Pay Agreements."

(3) Includes voluntary direct cash payments made to Energy Northwest and/or EWEB by Bonneville when the related Energy Northwest or Trojan Nuclear Project net billing participants' obligations to Energy Northwest

and/or EWEB exceed the allowed net billing credits. The Energy Northwest and Trojan Nuclear Project net billing agreements provide that, under certain circumstances, Bonneville is to reassign a net billing participant's shares of related projects, if Bonneville anticipates that the billings by Bonneville to the participant are expected to be less than the amounts to be paid by the participant to Energy Northwest and/or EWEB. Bonneville obviates the need to provide for such reassignments by making voluntary direct cash payments to Energy Northwest and/or EWEB on the related net billing participant's behalf. Bonneville and Energy Northwest propose to enter into certain agreements under which Bonneville would have a contractual obligation to fund the costs of Energy Northwest's Net Billed Projects on a cash payment basis. See "—Proposed Direct Pay Agreements."

BONNEVILLE LITIGATION

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 were 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, Reclamation, and Bonneville (collectively, the "Action Agencies")—and to prepare a new biological opinion. Plaintiffs subsequently filed a first amended complaint, and the action agencies filed their answer. Several entities have intervened in this lawsuit. The court heard oral argument on motions for summary judgment in April 2003.

In early May 2003, the U.S. District Court judge issued a decision on the adequacy of the 2000 Biological Opinion. The ruling provides that the 2000 Biological Opinion was inadequate because it relied on offsite mitigation measures that were "not reasonably certain to occur" and because the biological opinion used an "action area" (the geographically delineated area comprising where the dam's operation directly or indirectly affect listed species) that was too small. In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. Plaintiffs have filed a request to extend the deadline to complete the remand to March 1, 2007.

On November 30, 2004, NOAA Fisheries finalized a new biological opinion (the "2004 Biological Opinion") to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court. For a discussion of the 2004 Biological Opinion, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—2000 and 2004 Biological Opinions." Plaintiffs filed a complaint against NOAA Fisheries with the District Court, alleging that the 2004 Biological Opinion violates certain provisions of the ESA. On May 26, 2005, the court issued an opinion identifying several deficiencies in the 2004 Biological Opinion. The ruling was finalized in October 2005, and the court remanded the matter to the Federal agencies to correct identified deficiencies. The Federal Government and the State of Idaho have filed appeals and are seeking an expedited hearing before the Ninth Circuit Court. Additionally, in the court's October remand order, the sovereign parties (states, Federal agencies and tribes) were ordered to undertake collaboration to address key issues in a new biological opinion currently being prepared by the Federal agencies. The remand is to last a year from the October 2005 court order, although if adequate progress is being made and more time is needed, the court has indicated that an extension may be granted.

There has also been related litigation in which plaintiffs have sought injunctive relief on certain Federal System dam operations that were included in the original 2004 Biological Opinion. In the fall of 2005, plaintiffs sought injunctive relief for Federal System dam operations that would occur during the year-long remand of the 2004 Biological Opinion described above. This request is similar to a request for injunctive relief that plaintiffs filed with respect to 2005 dam operations. In the summer of 2005, the court granted plaintiffs' request seeking additional summer spill to aid downstream migration of juvenile salmon and steelhead species. When water is spilled, it is diverted through dam spillways and does not run through hydroelectric turbines, thereby reducing power generation. Bonneville estimates that the court-ordered spill resulted in about $75 million in foregone power revenues in fiscal year 2005 when compared to the revenues that would have accrued had summer spill occurred as required under the 2004 Biological Opinion.

With respect to the 2006 river operations, the Federal Government proposed (and the court approved) a spill program that is similar although not identical to the spill program the court had ordered in the summer of 2005. Bonneville estimates that the 2006 spill order, which includes spring as well as summer spill, will result in somewhat greater hydroelectric generation than occurred under the 2005 summer spill program, but this estimate varies depending on what water conditions ultimately take place.

See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—2000 and 2004 Biological Opinions."

DSI Service ROD Litigation

On June 30, 2005, Bonneville issued a record of decision entitled "Bonneville Power Administration's Service to the Direct Service Industrial Customers for Fiscal Years 2007-2011" ("DSI ROD"). The DSI ROD establishes a policy that Bonneville will use to define service benefits that Bonneville may provide to the DSIs during fiscal years 2007 through 2011, among other things.

On September 28, 2005, Alcoa, Inc., ("Alcoa"), a Bonneville direct service industrial customer, filed a petition for review in the Ninth Circuit Court challenging the DSI ROD. On the same day, the Pacific Northwest Generating Cooperative ("PNGC"), a consortium of Bonneville Preference Customers, filed a separate petition for review. Although Alcoa's legal theory is unknown at this time, PNGC has contended that Bonneville lacks statutory authority to provide service benefits to the DSIs. The two petitions have been consolidated, and the cases have been stayed until March 2006.

Slice Litigation

On November 17, 2003, a group of Bonneville's Slice customers ("Benton Petitioners") filed a petition with the Ninth Circuit Court challenging Bonneville's final determinations under the Slice Agreements of a Slice true-up adjustment charge, which is an annual adjustment to the Slice Rate. (The true-up charge is described in "POWER BUSINESS LINE—Power Marketing in Fiscal Years 2002 through 2006—Preference Customer and Federal Agency Loads.") The Benton Petitioners assert that Bonneville's Slice true-up adjustment charge for contract year 2002 is inconsistent with the terms of the Slice contracts and that the Slice customers' audit of fiscal year 2002 charges revealed $83 million in overcharges. The Benton Petitioners further assert that the court lacks jurisdiction to resolve the dispute because the Slice contracts require binding arbitration for such disputes.

On October 23, 2003, a group of Bonneville's full requirements Preference Customers, represented by the Northwest Requirements Utilities ("NRU"), a trade association, filed a petition in the Ninth Circuit Court challenging the same Slice true-up adjustment charge. The NRU Petitioners challenge different aspects of Bonneville's Slice true-up adjustment charge than the Benton Petitioners and are concerned that if the Benton Petitioners were to prevail, the result would be a cost shift to the NRU Petitioners of up to $84 million. In addition, the petition also challenges the Slice customers' assertion that the Slice contract requires the use of binding arbitration as a means to resolve a rate determination of Bonneville under the Northwest Power Act.

The petitions filed by the NRU Petitioners and Benton Petitioners have been consolidated and the cases have been fully briefed and argued. The parties are awaiting a decision by the court.

On March 16, 2004, the NRU Petitioners filed an additional petition for review ("NRU II"). The reason for the new petition is that Bonneville's determination of the Slice true-up adjustment charge is an annual determination. On December 18, 2003, Bonneville made a final decision regarding its 2003 Slice true-up adjustment charge and billed the Slice customers for 2003 annual true-up adjustment charges. The NRU Petitioners filed for review of the 2003 determination, and asked the court to stay the litigation pending the resolution of NRU I, described above. In April 2004, the Slice customers filed a motion to intervene in NRU II. The court granted the Slice customers' motion to intervene and has stayed the case until April 2006, or until NRU I is decided, whichever comes first. Bonneville and the other Slice litigants have retained a mediator and are attempting to resolve the entire dispute.

2002 Final Power Rates Challenge

Numerous Bonneville customers have filed petitions for review in the Ninth Circuit Court challenging Bonneville's 2002 Final Power Rates Proposal. The rates have been confirmed and approved by FERC. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in Fiscal Years 2002 through 2006." Briefing has been completed and oral argument was held in November 2005.

City of Burbank, California v. United States

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

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

As part of filing its claim under the Contract Disputes Act, Burbank, as well as the cities of Glendale and Pasadena, submitted certified claims (known as Counts I & II) 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 (known as Count III) 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 Board of Contract Appeals (the "Board"). In response, Bonneville filed a motion to dismiss for lack of subject matter jurisdiction, and in January 2004 the motion was denied. A hearing on the merits was held before the Board in May 2004. On April 14, 2005, the Board ruled against the three cities on their combined claims (Counts I & II) finding that Bonneville did not improperly calculate the applicable power rate under the related Exchange Agreements. In the same decision, the Board ruled against Bonneville on Count III finding that Bonneville improperly notified Burbank of the change between sale and exchange modes. As damages for Count III, the Board ordered an award against Bonneville in the amount of $524,550 plus interest for about two years.

Bonneville has fully satisfied the judgment awarded to Burbank under Count III, including applicable interest. The three cities have filed an appeal of the Board's decision on Counts I & II with the U.S. Court of Appeals for the Federal Circuit; briefing is currently underway.

Residential Exchange Program Litigation

In connection with the implementation of the Subscription Strategy, 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 Fiscal Years 2002 through 2006."

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 and the related records of decisions prepared by Bonneville. A number of interventions have also been filed in the foregoing challenges. Among those participating in the litigation are a group of DSIs, all six Regional IOUs and a number of Preference Customers and Preference Customer groups.

The petitions for review do not specify the precise nature of the challenges to Bonneville's final actions with regard to the RPSAs and the Residential Exchange Settlement Agreements, but allege generally that the RPSAs and Residential Exchange Settlement Agreements violate the Bonneville Project Act, the Pacific Northwest Consumer Power Preference Act, the Transmission System Act, the Northwest Power Act, NEPA, and/or the Administrative Procedure

Act. Bonneville expects the likely remedies sought would be that the Residential Exchange Settlement Agreements, and/or RPSAs, be remanded to Bonneville for redevelopment or that Regional IOUs be allowed only to participate in the Residential Exchange Program under the RPSAs.

In June 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements that affect such Regional IOUs' Residential Exchange Settlement Agreements. Among other things, these additional agreements reduced Bonneville's obligation to sell power to meet loads of Puget and PacifiCorp and to reduce by one half certain payments in the aggregate amount of $200 million that Bonneville otherwise owed to the two subject Regional IOUs in fiscal years 2005 and 2006 under their Residential Exchange Settlement Agreements.

In addition, with respect to the other four Regional IOUs, Bonneville has also entered into agreements having terms similar to those for Puget and PacifiCorp, although the reduction in financial payments that Bonneville will make to such Regional IOUs in the current rate period will be only $3-$4 million in aggregate. For a discussion of the foregoing agreements with the Regional IOUs see "POWER BUSINESS LINE—Power Marketing in Fiscal Years 2002 through 2006—Residential Exchange Program Obligations." The Ninth Circuit Court has granted a motion to dismiss the challenges to the RPSAs. Several of Bonneville's customers have also filed lawsuits in the Ninth Circuit Court challenging the June 2004 agreements between Bonneville and the related Regional IOUs. On November 14, 2005, oral argument was held before the Ninth Circuit Court on: (1) challenges to Bonneville's Residential Exchange Settlement Agreements; (2) Bonneville's entry into the load reduction agreements with PacifiCorp and Puget; and, (3) Bonneville's entry into the amendments to the Residential Exchange Settlement Agreements.

Southern California Edison v. Bonneville Power Administration

Southern California Edison ("SCE") 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 sale contract ("Sale and Exchange Agreement") between Bonneville and SCE.

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

The current status of the claims is as follows:

Conversion from Sale to Exchange Mode. Rather than await a Contracting Officer's Decision, SCE filed an action in the Court of Federal Claims on December 26, 2002, based on its assertion that the claim should be "deemed denied" by Bonneville SCE's complaint seeks damages in the amount of approximately $186,000,000. Bonneville filed a motion to dismiss for failure to state a claim for which relief can be granted. On October 24, 2003 the motion was denied. The court has stayed discovery pending the outcome of settlement discussions.

Challenge to FPS-96R. Bonneville notified SCE that the claim was a challenge to Bonneville's rates, and such challenges are cognizable only in the Ninth Circuit Court of Appeals. On December 30, 2003, SCE filed a complaint in the Court of Federal Claims. SCE's complaint seeks damages in the amount of $32,000,000. In November 2004, Bonneville filed a motion to dismiss the complaint for lack of subject matter jurisdiction. On November 10, 2005, this motion was denied. The parties are currently engaged in discovery on this claim.

Termination for Default. In July 2001, Bonneville terminated the Sale and Exchange Agreement for default, citing SCE's failure to make timely energy returns and deliveries while the contract was in exchange mode. In August of 2003, SCE filed an administrative claim with Bonneville under the Contract Disputes Act for wrongful termination in the amount of $22,000,000. Bonneville refused to entertain the administrative claim, citing the one-year statute of limitations for challenging a final contracting officer's decision. Subsequently, SCE filed a complaint in November 2004 seeking $22,000,000 in termination for convenience damages. Bonneville filed a motion to dismiss for lack of subject matter jurisdiction. The court has preliminarily dismissed Bonneville's motion pending the outcome of settlement discussions. In the event the claim is not settled, the court will reinstate Bonneville's motion.

Fiscal Year 2004 SN-CRAC Adjustment Litigation

In June through August of 2004, petitioners Public Power Council, a number of DSIs, the Canby Utility Board, and the Industrial Customers of Northwest Utilities ("Petitioners") filed petitions for review in the Ninth Circuit Court. Petitioners challenge Bonneville's establishment of the SN-CRAC as confirmed and approved by FERC, and seek to have the SN-CRAC declared invalid by the court. Briefing has been completed and oral argument is scheduled for March 8, 2006.

Kaiser Aluminum Bankruptcy

Kaiser Aluminum and Chemical, Incorporated ("Kaiser"), a subsidiary of Kaiser Aluminum Corporation, is one of Bonneville's aluminum company DSI customers. On February 12, 2002, both Kaiser and its parent corporation Kaiser Aluminum Corporation filed for bankruptcy protection. Bonneville had a contract (the "Kaiser Contract") to sell Kaiser about 291 megawatts of electric power during the five-year period beginning October 1, 2001. 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 will 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. Kaiser rejected the Kaiser Contract in the bankruptcy proceeding. The consequence of this rejection is that the "take or pay" obligation that Kaiser owes to Bonneville for future deliveries will be treated as a general unsecured claim.

The United States Department of Justice, acting on behalf of Bonneville, has filed a proof-of-claim in the amount of $78 million in this proceeding, reflecting the value of contracts Bonneville has with Kaiser. Kaiser's plan for reorganization provides that unsecured creditors will be paid for any allowed claims in stock of the reorganized company, and that the value of such stock will represent less that three cents on the dollar for each such claim.

In October 2005, Kaiser filed a motion objecting to Bonneville's take-or-pay claim. Kaiser's motion argues that market prices far exceeded the contract price so that Bonneville incurred no actual damages (other than for the unpaid pre-petition amount of approximately $1 million) due to Kaiser's rejection of the power sales contract. Bonneville has proposed a settlement that would reduce the amount of Bonneville's take-or-pay claim based on calculating such damages using actual (lower) contract rates for the take- or-pay period.

Yakama Nation Litigation

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

Northwest Environmental Defense Center Litigation

On January 23, 2006, the Northwest Environmental Defense Center, Public Employees for Environmental Responsibility, and Northwest Sportfishing Industry Association petitioned the Ninth Circuit Court to review Bonneville's transfer of certain data gathering and analysis functions from an entity called the Fish Passage Center to the Pacific States Marine Fisheries Commission and Battelle Pacific Northwest Laboratory. The petitioners allege Bonneville would violate the Northwest Power Act if Bonneville ceases to obtain these data gathering and analysis functions from the Fish Passage Center. The Fish Passage Center's $1.3 million contract with Bonneville was due to expire on March 19, 2006. But on March 17, 2006, the Ninth Circuit granted a motion to stay filed by the Northwest Environmental Defense Center and the Yakama Nation. As a consequence, Bonneville has extended the Fish Passage Center's contract through April 19, 2006, and will extend it further after deciding on the next steps in these cases.

CPN Cascade, Inc. v. United States

In September 1994, CPN Cascade Inc. (then d/b/a CE Newberry, Inc.) and Bonneville entered into a Power Purchase Agreement for power from a proposed geothermal project in central Oregon. To resolve a contract dispute, Bonneville and CE Newberry, Inc. entered into a settlement agreement in 1996.

On December 19, 2005, CPN Cascade, Inc. (the successor in interest to CE Newberry, Inc. and a wholly-owned subsidiary of the now-bankrupt entity Calpine Corporation) filed a lawsuit against Bonneville. CPN Cascade Inc. claims Bonneville is in breach of the 1996 settlement agreement and seeks $9 million in damages.

The United States Department of Justice, on behalf of Bonneville, filed an answer to the lawsuit on March 8, 2006.

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's power rates for the five years beginning October 1, 2001 and the SN-CRAC rate level adjustment mechanism have been reviewed and approved by FERC. Bonneville's transmission rates have been approved by FERC and are in effect for the two years beginning October 1, 2005. See "POWER BUSINESS LINE—Power Marketing in Fiscal Years 2002 through 2006," "TRANSMISSION BUSINESS LINE—Bonneville's Transmission and Ancillary Service 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.

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PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying combined balance sheets and the related combined statements of changes in capitalization and long-term liabilities, of revenues and expenses and of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2005 and 2004, and the results of its operations and its cash flows for the three years in the period ended September 30, 2005, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2005, 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. Those standards 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.

PricewaterhouseCoopers LLP

Portland, Oregon
November 1, 2005

SELECTED QUARTERLY INFORMATION (Unaudited)

Federal Columbia River Power System

3 months ended — thousands of dollars

	December 31	March 31	June 30	September 30	Totals
2005					
Revenues	**$776,805**	**$805,778**	**$701,765**	**$ 889,139**	**$3,173,487**
SFAS 133 mark-to-market	**(8,826)**	**15,040**	**1,914**	**86,468**	**94,596**
Operating revenues	**767,979**	**820,818**	**703,679**	**975,607**	**3,268,083**
Operating expenses	**587,015**	**622,066**	**642,559**	**652,289**	**2,503,929**
Net interest expenses	**71,491**	**70,697**	**67,442**	**67,654**	**277,284**
Net revenues (expenses)	**$109,473**	**$128,055**	**$ (6,322)**	**$ 255,664**	**$ 486,870**
2004					
Revenues	$823,281	$755,437	$702,847	$ 826,894	$3,108,459
SFAS 133 mark-to-market	(1,210)	29,623	85,396	(24,357)	89,452
Operating revenues	822,071	785,060	788,243	802,537	3,197,911
Operating expenses	577,734	532,174	611,850	686,887	2,408,645
Net interest expenses	74,576	75,169	67,501	67,605	284,851
Net revenues	$169,761	$177,717	$108,892	$ 48,045	$ 504,415
2003					
Revenues	$898,748	$901,112	$760,233	$ 996,746	$3,556,839
SFAS 133 mark-to-market	47,134	(25,904)	24,712	9,323	55,265
Operating revenues	945,882	875,208	784,945	1,006,069	3,612,104
Operating expenses	698,279	740,185	490,416	782,209	2,711,089
Net interest expenses	87,712	85,144	81,546	91,189	345,591
Net revenues	$159,891	$ 49,879	$212,983	$ 132,671	$ 555,424

Combined Balance Sheets

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

Assets

	2005	2004
Federal utility plant		
Completed plant	**$12,722,386**	$12,243,684
Accumulated depreciation	**(4,453,745)**	(4,357,496)
	8,268,641	7,886,188
Construction work in progress	**1,152,978**	1,401,793
Net federal utility plant	**9,421,619**	9,287,981
Nonfederal generation	**2,389,445**	2,368,314
Current assets		
Cash	**651,740**	654,242
Accounts receivable, net of allowance	**88,184**	91,517
Accrued unbilled revenues	**208,801**	158,074
Materials and supplies, at average cost	**75,073**	81,246
Prepaid expenses	**321,032**	331,383
Total current assets	**1,344,830**	1,316,462
Other assets		
Regulatory assets	**5,509,596**	5,584,062
Nonfederal nuclear decommissioning trusts	**125,509**	111,941
Deferred charges and other	**234,773**	264,019
Total other assets	**5,869,878**	5,960,022
Total assets	**$19,025,772**	$18,932,779

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2005	2004
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 1,334,294**	$ 847,424
Federal appropriations	**4,272,662**	4,339,288
Bonds issued to U.S. Treasury	**2,211,800**	2,461,800
Nonfederal projects debt	**6,286,559**	6,218,932
Total capitalization and long-term liabilities	**14,105,315**	13,867,444
Commitments and contingencies (Note 7)		
Current liabilities		
Federal appropriations	**68,939**	104,673
Bonds issued to U.S. Treasury	**565,000**	438,500
Nonfederal projects debt	**207,490**	234,896
Accounts payable and other	**322,497**	338,867
Total current liabilities	**1,163,926**	1,116,936
Other Liabilities		
Regulatory liabilities	**2,129,660**	2,161,401
IOU exchange benefits	**984,187**	1,008,296
Nonfederal nuclear asset retirement obligations	**160,600**	164,000
Deferred credits	**482,084**	614,702
Total other liabilities	**3,756,531**	3,948,399
Total Capitalization and Liabilities	**$19,025,772**	$18,932,779

The accompanying notes are an integral part of these statements.

Combined Statements of Revenues and Expenses

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

	2005	2004	2003
Operating revenues			
Sales	**$ 3,051,976**	$ 2,973,496	$ 3,328,277
SFAS 133 derivative mark-to-market	**94,596**	89,452	55,265
Miscellaneous revenues	**63,811**	57,963	53,678
U.S. Treasury credits for fish	**57,700**	77,000	174,884
Total operating revenues	**3,268,083**	3,197,911	3,612,104
Operating expenses			
Operations and maintenance	**1,256,576**	1,211,802	1,198,521
Purchased power	**580,213**	582,129	1,043,009
Nonfederal projects	**291,540**	248,475	119,534
Federal projects depreciation and amortization	**375,600**	366,239	350,025
Total operating expenses	**2,503,929**	2,408,645	2,711,089
Net operating revenues	**764,154**	789,266	901,015
Interest expense			
Interest on federal investment:			
Appropriated funds	**192,110**	213,041	212,391
Bonds issued to U.S. Treasury	**102,077**	110,251	166,598
Allowance for funds used during construction	**(16,903)**	(38,441)	(33,398)
Net interest expense	**277,284**	284,851	345,591
Net revenues	**486,870**	504,415	555,424
Accumulated net revenues (expenses), Oct. 1	**847,424**	343,748	(211,676)
Irrigation assistance	**—**	(739)	—
Accumulated net revenues, Sept. 30	**$ 1,334,294**	$ 847,424	$ 343,748

The accompanying notes are an integral part of these statements.

COMBINED STATEMENTS OF CHANGES IN CAPITALIZATION AND LONG-TERM LIABILITIES

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

	Accumulated Net (Expenses) Revenues	Appropriations	Bonds Issued to Treasury	Nonfederal Project Debt	Total
Balance at Sept. 30, 2003	$ 343,748	$4,680,960	$ 2,697,754	$ 6,286,593	$14,009,055
Federal appropriations:					
Increase for construction	—	78,047	—	—	78,047
Repayment of construction	—	(315,046)	—	—	(315,046)
Bonds issued to U.S. Treasury:					
Increase	—	—	480,000	—	480,000
Repayment	—	—	(277,454)	—	(277,454)
Nonfederal projects debt:					
Net increase	—	—	—	179,130	179,130
Repayment	—	—	—	(11,895)	(11,895)
Net revenues	504,415	—	—	—	504,415
Irrigation assistance	(739)	—	—	—	(739)
Balance at Sept. 30, 2004	$ 847,424	$4,443,961	$ 2,900,300	$ 6,453,828	$14,645,513
Federal appropriations:					
Increase for construction	**—**	**75,642**	**—**	**—**	**75,642**
Repayment of construction	**—**	**(178,002)**	**—**	**—**	**(178,002)**
Bonds issued to U.S. Treasury:					
Increase	**—**	**—**	**315,000**	**—**	**315,000**
Repayment	**—**	**—**	**(438,500)**	**—**	**(438,500)**
Nonfederal projects debt:					
Increase	**—**	**—**	**—**	**47,513**	**47,513**
Repayment	**—**	**—**	**—**	**(7,292)**	**(7,292)**
Net revenues	**486,870**	**—**	**—**	**—**	**486,870**
Balance at Sept. 30, 2005	**$1,334,294**	**$4,341,601**	**$ 2,776,800**	**$ 6,494,049**	**$14,946,744**

The accompanying notes are an integral part of these statements.

Combined Statements of Cash Flows

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

	2005	2004	2003
Cash provided by operating activities			
Net revenues	**$ 486,870**	$ 504,415	$ 555,424
Non-cash items:			
Depreciation	**305,281**	294,975	269,957
Amortization	**70,319**	71,264	77,610
Amortization of capitalization adjustment	**(64,905)**	(68,566)	(67,703)
(Increase) decrease in:			
Receivables and unbilled revenues	**(47,394)**	87,594	(38,144)
Materials and supplies	**6,173**	3,061	801
Prepaid expenses	**10,351**	(43,316)	(2,372)
(Decrease) increase in:			
Accounts payable and other	**(16,370)**	(30,954)	26,396
Other	**(72,832)**	(152,601)	51,802
Cash provided by operating activities	**677,493**	665,872	873,771
Cash used for investment activities			
Investment in:			
Federal utility plant (including AFUDC)	**(424,735)**	(576,324)	(535,211)
Nonfederal projects	**(40,221)**	(47,650)	(85,050)
Conservation	**(14,825)**	(16,876)	(25,458)
Fish and wildlife	**(14,575)**	(5,849)	(11,156)
Cash used for investment activities	**(494,356)**	(646,699)	(656,875)
Cash provided by and used for financing activities			
Federal construction appropriations:			
Increase	**75,642**	78,047	99,418
Repayment	**(178,002)**	(315,046)	(61,060)
Bonds issued to U.S. Treasury:			
Increase	**315,000**	480,000	470,000
Repayment	**(438,500)**	(277,454)	(482,687)
Refinanced	**—**	—	(60,000)
Nonfederal debt:			
Increase	**47,513**	179,130	99,289
Repayment	**(7,292)**	(11,895)	(14,239)
Irrigation assistance	**—**	(739)	—
Cash (used for) provided by financing activities	**(185,639)**	132,043	50,721
(Decrease) Increase in cash	**(2,502)**	151,216	267,617
Beginning cash balance	**654,242**	503,026	235,409
Ending cash balance	**$ 651,740**	$ 654,242	$ 503,026

The accompanying notes are an integral part of these statements.

1. Summary of Significant Accounting Policies

Principles of Combination

The Federal Columbia River Power System (FCRPS) combines the accounts of the Bonneville Power Administration (BPA), the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) and the operation and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan Facilities. Northwest Infrastructure Financing Corporation (NIFC), a "Special Purpose Corporation" formed on Dec. 17, 2003, has been consolidated with BPA for fiscal years 2004 and 2005. See Note 4 Nonfederal Projects and Related Debt.

BPA is the power marketing administration that purchases, transmits and markets power for the FCRPS. Each of the foregoing entities 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 functions 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 U.S. Department of Energy; Reclamation and U.S. Fish and Wildlife are part of the U.S. Department of the Interior; and the Corps is part of the U.S. Department of Defense. U.S. government properties and income are tax-exempt. All material inter-company accounts and transactions have been eliminated from the combined financial statements.

Use of 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, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications were made to the fiscal years 2003 and 2004 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2005. Such reclassifications had no effect on previously reported results of operations and cash flows.

NOTES TO FINANCIAL STATEMENTS

Rates and Regulatory Authority

BPA's power and transmission rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are proposed by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. 839, and a standard set by the Energy Policy Act of 1992, 16 U.S.C. 824. FERC reviews BPA's rates for all firm power, non-firm energy 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 U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit Court). Action seeking such review must be filed within 90 days of the final FERC decision. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's General Counsel that, if a rate were rejected, it would be remanded to BPA for reformulation.

BPA submitted to FERC a Power Rate Filing in fiscal year 2001 for fiscal years 2002 through 2006. BPA submitted a Transmission and Ancillary Services Rate Filing in fiscal year 2003 for fiscal years 2004 through 2005 and in fiscal year 2005 for fiscal years 2006 through 2007. FERC granted final approval of the Power Rate Filing on July 21, 2003, 104 FERC 61,093 (2003). FERC granted final approval of BPA's Transmission and Ancillary Services Rate Filing for fiscal years 2004 through 2005 on Sept. 23, 2003, 104 FERC 62,207 (2003) and the Transmission and Ancillary Services Rate Filing for fiscal year 2006 through 2007 on Sept. 29, 2005, 112 FERC 62,258 (2005).

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 that rate levels may change under certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every six months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecast level of accumulated net revenues as modified in the General Rates Schedule Provisions (GRSP's) is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when BPA has missed or forecasts a 50 percent or greater probability of missing a payment to the U.S. Treasury or another creditor.

The LB CRAC percentage rate level increase was approximately 31.9 percent and 38.5 percent, respectively, for the six-month periods beginning Oct. 1, 2002, and April 1, 2003. The LB CRAC percentage increase was revised to approximately 21.3 percent and 24.6 percent, respectively, for the six-month periods beginning Oct. 1, 2003 and April 1, 2004. The LB CRAC percentage increase was revised to approximately 21.7 percent and 25.8 percent, respectively, for the six-month periods beginning Oct. 1, 2004 and April 1, 2005.

The August 2002 forecast of the generation function's accumulated net revenues as modified in the GRSP's for computing the FB CRAC thresholds triggered the FB CRAC, and resulted in a rate increase over base rates of approximately 11 percent for fiscal year 2003, approximately 12 percent for fiscal year 2004, and approximately 11 percent for fiscal year 2005 for most of the requirements rates. The increases were in addition to rate level increases under the LB CRAC.

The SN CRAC first triggered in fiscal year 2003, requiring an expedited rate proceeding resulting in a rate level increase that went into effect Oct. 1, 2003 through Sept. 30, 2004, of approximately 10 percent. The expedited rate case also enabled the recalculation of the FB CRAC thresholds. This ensures that the FB CRAC collects the maximum amount possible before the SN CRAC is calculated. The changes in the FB CRAC avoid cost shifts between the different customers to which the FB and SN CRACs apply. BPA submitted to FERC a separate power rate filing in fiscal year 2003 related to the design of the SN CRAC. FERC granted final approval of the filing on May 10, 2004, 107 FERC 61,138 (2004). The SN CRAC rate filing augments the power rates already approved for fiscal years 2002 through 2006 including rate level increases under the LB CRAC and FB CRAC. The SN CRAC was set to zero percent for FY 2005.

Rate adjustment clauses are calculated initially on forward-looking estimates of revenues and expenses, with adjustments made to future rates after financial results are known.

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percentage of BPA's power costs in exchange for a fixed percentage of generation output. Settlement of any over or under collection occurs in the subsequent year. For the fiscal year 2003 settlement, BPA recognized a $30.4 million liability which was paid in fiscal year 2004. For the fiscal year 2004 settlement, BPA recognized a receivable of $10.1 million which was received in fiscal year 2005. For the fiscal year 2005 settlement, BPA recognized a receivable of $43.3 million, to be received in fiscal year 2006.

BPA's rates are subject to the regulatory oversight described above and are designed to recover its cost of service. In connection with the rate-setting process, certain costs or credits may be included in rates for recovery over a period of time that differs from normal treatment under generally accepted accounting principles. Under those circumstances, regulatory assets or liabilities are recorded and such costs or credits are amortized over the periods they are included in rates in accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation."

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 deferred costs and revenues under that standard would be expensed and recognized, respectively, in the Statement of Revenues and Expenses in that period. Amortization of these costs is reflected in the

Regulatory Assets and Liabilities

As of Sept. 30 — thousands of dollars

	2005	2004
Regulatory Assets		
Nonfederal projects:		
Conservation	**$ 40,264**	$ 43,566
Terminated hydro facilities	**27,305**	28,090
Terminated nuclear facilities	**3,917,450**	3,894,273
Decommissioning cost	**35,091**	52,059
IOU exchange benefits	**963,539**	988,259
Conservation	**298,189**	335,827
Fish and wildlife	**113,776**	116,910
Settlements	**51,592**	85,392
Federal Employee Compensation Act	**33,158**	—
Capital bond premiums	**22,632**	26,486
Additional post-retirement contributions	**6,600**	13,200
Total Regulatory Assets	**5,509,596**	5,584,062
Regulatory Liabilities		
Capitalization adjustment	**1,991,226**	2,056,131
Accumulated plant removal costs	**119,454**	105,270
Other	**18,980**	—
Total Regulatory Liabilities	**2,129,660**	2,161,401
Net Regulatory Assets and Liabilities	**$3,379,936**	$3,422,661

Statements of Revenues and Expenses. BPA does not earn a rate of return on its regulatory assets.

The previous table summarizes regulatory assets and liabilities as of Sept. 30, 2005, and 2004.

Federal Utility Plant

Federal 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. The cost of federal utility plant retired is charged to accumulated depreciation when it is removed from service. The net cost of removal (the difference between cost of removal and salvage) is charged to the regulatory liability when cost of removal exceeds salvage. Federal utility plant in the Statements of Cash Flows is reported net of the accrued plant removal costs and accumulated depreciation.

Federal Projects Depreciation and Amortization

Depreciation of original cost and estimated cost to retire federal utility plant (i.e., net cost of removal) 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 up to 20 years for conservation and 15 years for fish and wildlife.

Allowance for Funds Used During Construction

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

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for Corps and Reclamation generating projects and were 2.1 percent to 4.9 percent in fiscal year 2005, 1.3 percent to 5.3 percent in fiscal year 2004, and 1.8 percent to 6.3 percent in fiscal year 2003.

AFUDC capitalization rates for BPA's construction projects were approximately 4.9 percent in fiscal year 2005, 5.3 percent in fiscal year 2004, and 6.3 percent in fiscal year 2003. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

SFAS 143, "Accounting for Retirement Obligations," requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, and for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as a liability. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. FCRPS has certain tangible long-lived assets for which AROs are not measurable. An ARO will be required to be recorded when circumstances change. Assets that may require removal when no longer in service include the hydro projects and transmission facilities.

Pursuant to regulation, BPA recovers through rates estimated removal costs and records them as accumulated plant removal costs. At Sept. 30, 2005 and 2004, BPA has estimated these regulatory liabilities to be $119.5 million and $105.3 million, respectively.

Nonfederal Generation

BPA has acquired all of the generating capability of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant. The contract to acquire the generating capability of the project, referred to as "a net-billing agreement," requires BPA to pay all or part of the annual project budget, including operating expense and debt service. BPA also has acquired all of the output of the Cowlitz Falls hydro project and agreed to pay the operating expense and debt service. BPA recognizes expenses for these projects based upon total project cash funding requirements. The nonfederal generation assets in the Balance Sheets are amortized as the principal on the outstanding bonds is repaid. See Note 4 Nonfederal Projects and Related Debt.

Cash

For purposes of reporting cash flows, amounts include cash in the BPA fund and unexpended appropriations of the Corps and Reclamation. Cash paid for interest on appropriated funds and bonds issued to U.S. Treasury was $78 million, $102 million and $135 million in fiscal years 2005, 2004, and 2003, respectively. These amounts are net of U.S. Treasury credits and interest income earned on the Bonneville fund.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheets as of Sept. 30, 2005 and 2004. The carrying value reflected in the Balance Sheets approximates fair value for the FCRPS' financial assets and current liabilities. The fair values of bonds issued to U.S. Treasury and nonfederal projects are discussed in Notes 3 and 4 for Bonds issued to U.S. Treasury and Nonfederal Projects and Related Debt, respectively.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist primarily of BPA accounts receivable. Credit risk represents the loss that would be recognized if counterparties fail to perform as contracted.

BPA's accounts receivables are spread across a diverse group of public utilities, investor-owned utilities, power marketers, and others that are geographically located throughout the Western United States and Canada. The accounts receivable exposures result from BPA providing a wide variety of power products and transmission services. BPA's counterparties are generally large and stable and do not represent a significant concentration of credit risk. During fiscal year 2005, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure on a daily basis, and performing Credit Value at Risk (CVaR) measurements for forward power transactions on a weekly basis. In order to further manage credit risk, BPA obtains credit support such as letters of credit and third-party guarantees from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

Allowance for Doubtful Accounts

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific accounts, based upon the best available facts and circumstances, of customers that may be unable to meet their financial obligations, and a reserve based on historical experience. Management believes that the allowance for doubtful accounts as of Sept. 30, 2005, was adequate.

Credit Risk from California

California power markets were in turmoil several years ago and experienced historically high power prices and volatility along with the continued uncertainty related to deregulation. The California Independent System Operator and California Power Exchange, two customers with whom BPA had contracts for power and transmission delivery during that period have been unable to fully pay BPA for their purchases. BPA has recorded an allowance for doubtful accounts which in management's best estimate are sufficient to cover potential exposure. Net exposure after the allowance is not significant. Nonetheless, BPA is continuing to pursue collection of amounts due in bankruptcy and other proceedings.

Deferred Charges and Other

SFAS 133 derivative mark-to-market represents unrealized fair value gains of derivative contracts. The NIFC trust fund is held for construction of the Schultz-Wautoma transmission line. Energy receivable is energy to be returned to BPA for prior transmission line losses.

Deferred Charges and Other

As of Sept. 30 — thousands of dollars

	2005	2004
SFAS 133 derivative mark-to-market	**$175,591**	$172,713
NIFC trust fund	**26,731**	31,194
Energy receivable	**18,980**	—
Other	**13,471**	60,112
	$234,773	$264,019

Other is primarily Corps and Reclamation costs for generating assets not placed in service. The Corps disposed of generating units related to the Libby Dam of $40 million in fiscal year 2005.

The previous table summarizes deferred charges and other as of Sept. 30, 2005 and 2004.

Retirement Benefits

FCRPS employees are participants in either the Civil Service Retirement System (CSRS) or the Federal Employees Retirement System (FERS). Both FCRPS and its employees contribute a percentage of eligible employee compensation toward funding these defined post-retirement benefit plans. Based on the statutory contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 11.2 percent of eligible employee compensation. However, the legislatively mandated contribution levels do not fully cover the cost to the federal government to provide the plan benefits. Therefore, the programs are considered under funded. Employees also may be participants in the Federal Employees Health Benefits Program (FEHB) and/or the Federal Employees' Group Life Insurance Program (FEGLI); these plans are similarly under funded. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

In order to ensure that all post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed, FCRPS makes additional annual contributions to the U.S. Treasury. Because these costs are included in rates, the deferred amount has been recorded as a regulatory asset. FCRPS has a $6.6 million remaining liability as of Sept. 30, 2005, which is included in other current liabilities and deferred credits in the accompanying Balance Sheet representing the balance of deferred additional contributions from fiscal years 1998 through 2001. The liability is reduced as prior years' additional contributions are made. FCRPS expects to satisfy its prior year commitments for under funded post-retirement benefits by fiscal year 2007.

Deferred Credits

Revenues associated with advances for customer reimbursable projects are recognized in two different ways. If the customer will own the asset under construction, the revenue is recognized as the expenditures are incurred. If BPA will own the resulting asset, revenue is recognized over the life of the asset, once the corresponding asset is placed in service.

Deferred revenues for Third AC intertie capacity agreements are recognized over an estimated 49-year life of the related assets.

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

Up-front leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020.

The Federal Employees Compensation Act (FECA) authorizes income and medical cost protection to covered federal civilian employees that are injured on the job or that have incurred a work-related injury or occupational disease. The U.S. Department of Labor (DOL) administers compensation and medical benefits paid under FECA on behalf of the Federal Government. DOL is also responsible for calculating the FECA liability of future compensation benefits for all federal agencies. FCRPS records its respective portion of the actuarial liability for the estimated amount of future payment for workers' compensation benefits as a liability on its fiscal year 2005 Balance Sheet. This actuarial liability includes the expected liability for death, disability, medical and miscellaneous costs for approved compensation cases plus a component for incurred but not reported claims.

SFAS 133 derivative mark-to-market represents fair value of derivatives.

The table below summarizes deferred credits as of Sept. 30, 2005 and 2004.

Deferred Credits

As of Sept. 30 — thousands of dollars

	2005	2004
Customer reimbursable projects	**$ 177,419**	$183,933
Third AC intertie capacity agreements	**116,481**	119,546
Load diversification fees	**71,617**	81,163
Fiber optic leasing fees	**55,444**	59,335
Federal Employee Compensation Act	**33,158**	—
SFAS 133 derivative mark-to-market	**16,329**	106,513
Other	**11,636**	64,212
	$ 482,084	$614,702

SFAS 133 and Related Guidance

SFAS 133, "Accounting for Derivative Instrument and Hedging Activities," requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that change in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

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

For all other derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA does not apply hedge accounting.

BPA recorded a SFAS 133 mark-to-market unrealized gain in the Statement of Revenues and Expenses related to its derivative portfolio (including physical power purchase and sale transactions, power exchange transactions, and purchased options) of $94.6 million, $89.4 million and $55.3 million for fiscal years 2005, 2004 and 2003, respectively.

Purchased Options

In fiscal years 2005 and 2004, BPA purchased physical put options for the right to sell electricity at certain points in the future. With significant inventory risk due to currently unpredictable annual runoff, the put options allow BPA to hedge against falling prices without committing inventory and increasing the inventory risk.

BPA records purchased options on a mark-to-market basis and includes unrealized gains and losses in operating revenues in the Statement of Revenues and Expenses.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed LIBOR interest rate swaps to help manage interest rate risk related to its long-term debt portfolio. In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for 10 years and receives a variable rate that changes weekly tied to LIBOR. In the second swap transaction, BPA pays a fixed 3.5 percent on $200 million notional amount for 15 years and receives a variable rate that changes weekly tied to LIBOR. The floating interest rates on the swaps are reset on a weekly basis. The net effect of the two swap transactions is essentially replacing variable rate debt with 3.3 percent fixed rate debt. The swap transactions do not qualify for hedge accounting treatment under SFAS 133. BPA recorded a $4.3 million unrealized fair value gain, a $2.1 million unrealized fair value gain and a $7.9 million unrealized fair value loss in the Statements of Revenues and Expenses for fiscal years 2005, 2004 and 2003 respectively, related to the interest rate swap transactions.

EITF 03-11

Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes," requires that revenues and expenses associated with non-trading energy activities that are "booked out" (not physically settled) be reported on a net basis. EITF 03-11 is effective for all derivative contracts that settle after Sept. 30, 2003, and does not require the reclassification of prior period amounts. Effective with the Oct. 1, 2003 adoption of EITF 03-11, the non-physical settlement of non-trading electricity derivative activities, formerly recorded on a "gross" basis in both operating revenues and purchased power expense, are now recorded on a "net" basis in operating revenues. This change, which has no effect on margins, net revenue or cash flows, resulted in a $239 million and $212 million decrease to both operating revenues and purchased power expense for fiscal years 2005, and 2004, respectively. The determination of the sales and purchases of electricity that would have been reported on a net basis had EITF 03-11 been historically applied is not practicable. Prospective application of EITF 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts reported in comparative financial statements.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $209 million, $158 million and $190 million at Sept. 30, 2005, 2004 and 2003, respectively. For revenue purposes, BPA operates as two segments: the Power Business Line and the Transmission Business Line. In Note 8 Segments, the table reflects revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing administration, 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 7 Commitments and Contingencies.

U.S. Treasury Credits for Fish

The Northwest Power Act of 1980 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. The Northwest Power Act 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 Northwest Power Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects. In the early 1990s, BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism whereby BPA reduces its cash payments to the U.S. Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes. BPA has taken U.S. Treasury credits for fish annually since 1995.

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets – An Amendment of APB Opinion No. 29, Accounting for Nonmonetary Transactions," which redefines the types of non-monetary exchanges that require fair value measurement. SFAS No. 153 is effective for nonmonetary exchanges made in fiscal years beginning after June 15, 2005. Adoption of this new standard in fiscal year 2006 is not expected to have a material impact on BPA's financial condition, results of operations or cash flows.

In March 2005, the FASB issued FASB Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143." FIN 47 clarifies that an entity is required to recognize a liability for a legal obligation to perform an asset retirement activity if the fair value can be reasonably estimated even though the timing and (or) method of settlement are conditional on a future event. FIN 47 is effective no later than the end of fiscal years ending after Dec. 15, 2005; therefore, it would be applicable no later than the end of BPA's fiscal year 2006. BPA is evaluating the effect of the adoption and implementation of FIN 47. Adoption of this guidance is not expected to have a material impact on BPA's financial condition, results of operations or cash flows.

2. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which BPA is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to the U.S. 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 in regulatory liabilities. 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 $64.9 million, $68.6 million and $67.7 million for fiscal years 2005, 2004 and 2003, respectively.

Construction and replacement of Corps and Reclamation generating facilities historically have been financed through annual federal appropriations. Annual appropriations also were made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. The Energy Policy Act of 1992 authorized BPA to directly fund 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 following table shows the term repayments on the remaining federal appropriations as of Sept. 30, 2005.

Federal Appropriations

As of sept. 30 — thousands of dollars

Term Repayments

2006	$ 68,939
2007	33,694
2008	10,913
2009	9,889
2010	26,327
2011+	4,191,839
	$ 4,341,601

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

The weighted average interest rate was 6.7 percent on outstanding appropriations as of Sept. 30, 2005.

3. Bonds issued to U.S. Treasury

To finance its capital programs, BPA is authorized by Congress to issue to the U.S. Treasury up to $4.45 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. Of the $4.45 billion, $1.25 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2005, of the total $2.78 billion of outstanding bonds, $779.8 million were conservation and renewable resource loans and grants (including Corps, Reclamation and U.S. Fish & Wildlife capital investments). 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 BPA bonds issued to U.S. Treasury, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2005, for similar maturities, exceeds carrying value by approximately $169 million, or 6.1 percent.

The following table reflects the terms and amounts of bonds issued to U.S. Treasury.

Bonds issued to U.S. Treasury

Long-Term Debt — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Amount	Cumulative Total
October 2002	none	2005	3.00%	$ 50,000	$ 50,000
November 2002	none	2005	2.80%	40,000	90,000
April 2003	none	2006	2.40%	40,000	130,000
April 2003	none	2006	2.40%	25,000	155,000
July 2003	none	2006	2.30%	75,000	230,000
July 2003	none	2006	2.30%	30,000	260,000
August 1996	none	2006	7.05%	70,000	330,000
September 2000	none	2006	6.75%	40,000	370,000
September 2002	none	2006	3.05%	100,000	470,000
September 2002	none	2006	3.05%	30,000	500,000
September 2002	none	2006	3.05%	20,000	520,000
September 2003	none	2006	2.50%	20,000	540,000
September 2003	none	2006	2.50%	25,000	565,000
December 2002	none	2006	3.05%	40,000	605,000
January 2004	none	2007	2.50%	60,000	665,000
January 2004	none	2007	2.50%	25,000	690,000
April 2003	none	2007	2.90%	40,000	730,000
April 2004	none	2007	2.95%	65,000	795,000
April 2004	none	2007	2.95%	35,000	830,000
July 2003	none	2007	2.95%	25,000	855,000
July 2004	none	2007	3.45%	50,000	905,000
July 2004	none	2007	3.45%	25,000	930,000
August 1997	none	2007	6.65%	111,300	1,041,300
September 2003	none	2007	3.10%	20,000	1,061,300
September 2004	none	2007	3.10%	30,000	1,091,300
September 2004	none	2007	3.10%	30,000	1,121,300
November 2004	none	2007	3.50%	20,000	1,141,300
January 2004	none	2008	2.95%	65,000	1,206,300
January 2004	none	2008	2.95%	30,000	1,236,300
January 2005	none	2008	3.60%	20,000	1,256,300
April 1998	none	2008	6.00%	75,300	$1,331,600
April 1998	none	2008	6.00%	25,000	1,356,600
June 2005	none	2008	3.95%	30,000	1,386,600
July 2004	none	2008	3.80%	25,000	1,411,600
August 1998	none	2008	5.75%	40,000	1,451,600
September 1998	none	2008	5.30%	104,300	1,555,900
September 2005	none	2008	4.25%	25,000	1,580,900
September 2005	none	2008	4.25%	20,000	1,600,900
November 2004	none	2008	3.75%	35,000	1,635,900
May 1998	none	2009	6.00%	72,700	1,708,600
May 1998	none	2009	6.00%	37,700	1,746,300
June 2005	none	2009	4.00%	40,000	1,786,300
July 1989	none	2009	8.55%	40,000	1,826,300
January 2001	none	2010	6.05%	60,000	1,886,300
January 2001	none	2010	6.05%	30,000	1,916,300
May 1998	none	2011	6.20%	40,000	1,956,300
June 2001	none	2011	5.95%	25,000	1,981,300
August 2001	none	2011	5.75%	50,000	2,031,300
January 1998	none	2013	6.10%	60,000	2,091,300
September 1998	none	2013	5.60%	52,800	2,144,100
February 1999	none	2014	5.90%	60,000	2,204,100
April 1998	2008	2028	6.65%	50,000	2,254,100
August 1998	none	2028	5.85%	106,500	2,360,600
August 1998	none	2028	5.85%	112,300	2,472,900
May 1998	2008	2032	6.70%	98,900	2,571,800
April 2003	2008	2033	5.55%	40,000	2,611,800
September 2004	2009	2034	5.60%	40,000	2,651,800
January 2005	2010	2035	5.40%	40,000	2,691,800
April 2005	2010	2035	5.50%	40,000	2,731,800
September 2005	2010	2035	5.25%	45,000	2,776,800
				$2,776,800	$2,776,800
Less current portion					(565,000)
					$2,211,800

All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

The weighted average interest rate was 4.8 percent on outstanding bonds issued to U.S. Treasury as of Sept. 30, 2005.

4. Nonfederal Projects and Related Debt

In addition to the CGS nuclear generating project, BPA has also acquired all or part of the generating capability of four other nuclear projects which are not providing power. These other projects are Energy Northwest Nuclear Project No. 1 (Project 1), Nuclear Project No. 3 (Project 3), 72 percent of the Hanford Generating Plant, and 30 percent of the Trojan project owned by Eugene Water and Electric Board (EWEB), Portland General Electric and PacifiCorp. The contracts to acquire the generating capability of the non-operating nuclear projects are also "net-billing agreements" requiring BPA to pay all or part of the annual projects' budgets, including maintenance expense and debt service. Project 1 and Project 3 were terminated prior to completion. Hanford and Trojan were decommissioned.

Along with the Cowlitz Falls hydro generating project, BPA has acquired all of the generating capability of Northern Wasco hydro project and agreed to pay the maintenance expense and debt service. However, the project was terminated prior to completion.

BPA has agreed to fund debt service on Emerald People's Utility District loans, Conservation and Renewable Energy System and City of Tacoma Conservation bonds, all issued to finance conservation programs sponsored by BPA.

Operating projects are included in nonfederal generation and non-operating projects are included in regulatory assets. See Note 1 Summary of Significant Accounting Policies. The debt for both the operating and non-operating nonfederal projects is included in nonfederal projects debt. BPA recognizes expenses for these projects based upon total project cash funding requirements.

Operating and maintenance expense for the projects of $257 million, $235 million and $223 million in fiscal years 2005, 2004 and 2003, respectively, is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $292 million, $248 million, and $120 million for fiscal years 2005, 2004 and 2003, 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 $116 million, or 1.9 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2005. All other nonfederal projects' debt approximates fair value as stated.

Construction of the Schultz-Wautoma transmission line was financed through NIFC. In March 2004, NIFC issued $119.6 million in taxable bonds to finance the line under a lease-purchase agreement. NIFC owns the line and BPA leases the line for 30 years. Lease revenues from BPA back the bonds.

BPA is constructing and will operate the line. BPA has indemnified the equity owners of NIFC for all construction and operating risks associated with the line. BPA will have exclusive use and control of the asset during the lease period. At the end of the lease, BPA has the option to buy the line for ten dollars. BPA has determined it is the primary beneficiary of NIFC. As such, NIFC financial statements are consolidated into BPA financial statements in accordance with FIN 46. The bonds are included as nonfederal debt on FCRPS' financial statements. NIFC's assets are included in FCRPS' other assets at Sept. 30, 2005. The following table summarizes future nonfederal projects principal payments as of Sept. 30, 2005.

Nonfederal Projects Debt

As of Sept. 30 — thousands of dollars

	Principal Payments
2006	$ 207,491
2007	295,350
2008	306,958
2009	311,294
2010	362,860
2011+	5,010,096
	$ 6,494,049

The weighted average interest rate was 5.5 percent on the major portion of outstanding nonfederal projects debt as of Sept. 30, 2005.

5. Nonfederal Nuclear AROs

The AROs for CGS, Project 1, and Trojan are $160.6 million and $164 million at Sept. 30, 2005 and 2004, respectively. BPA has funded $125.5 million for these AROs, which is held in trusts and recorded in the Balance Sheet. The trust fund balances are $95 million and $30.5 million for decommissioning and site restoration, respectively at Sept. 30, 2005. Payments to the trusts for fiscal years 2005, 2004 and 2003 were approximately $5.5 million, $5 million and $4.8 million, respectively. The unfunded amount will be collected in future rates and is included in regulatory assets in the Balance Sheet.

The following table presents the effects to the balances and activities in AROs for the accounting periods reported herein. Revisions were made in the current and prior years adjusting the accretion rates from the original model and calculation.

Nonfederal Nuclear AROs Activity

For the years ended Sept. 30 — thousands of dollars

	2005	2004	2003
Beginning Balance	**$164,000**	$126,000	$129,900
Activity:			
Expenditures	**(7,800)**	(7,900)	(7,000)
Accretion	**7,700**	6,800	3,100
Revisions	**(3,300)**	39,100	—
Ending Balance	**$160,600**	$164,000	$126,000

Decommissioning costs for CGS are charged to operations over the operating life of the project. An external decommissioning trust fund for costs is being funded monthly for CGS. The trust funds are expected to provide for decommissioning at the end of the project's safe storage period in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC requires that this deferred decontamination period be no longer than 60 years. Trust fund requirements for CGS are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning and site restoration expenditures for CGS are $673 million (2003 dollars). BPA has recorded an estimated liability of $98.2 million, $49.1 million and $13.3 million on a fair value basis for CGS and Trojan decommissioning costs, and Project 1 site restoration, respectively.

In fiscal years 2004 and 2005, BPA directly funded Trojan decommissioning expenses. BPA will continue to recover EWEB's 30 percent share of Trojan's costs through rates. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses. These costs incorporate the impact of SFAS 143.

6. Investor-owned Utility Exchange Benefits

As provided for in the Northwest Power Act, beginning in 1982 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 on the "exchanged" power. These payments were required to be passed through to their qualified residential and small-farm customers.

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

In October 2000, BPA's investor-owned utility (IOU) customers signed Subscription settlement agreements, under which BPA was to provide monetary and power benefits in place of residential exchange benefits for the period July 1, 2001, through Sept. 30, 2011. These agreements provide for both sales of power and monetary benefit payments to the IOUs and also allow the power to be converted to cash payments.

Amendments to the October 2000 contracts allowed payment of a portion of the fiscal year 2003 IOU Subscription settlement benefits to be deferred and paid in the fiscal year 2007 through 2011 period, except when they were reduced through credits to offset the SN CRAC.

In May 2004, BPA signed new contracts and amendments with all six IOU customers entitled "Agreements Regarding Payment of Residential Exchange Program Settlement Benefits During Fiscal Years 2007-2011." These latest agreements established a method for calculating the IOUs' Monetary Benefits for the fiscal years 2007 through 2011 period including an annual floor of $100 million and an annual cap of $300 million for the six IOUs in total, and all parties agreed that BPA would have no obligation to provide power to the IOUs during that period. The new agreements also eliminated $100 million of a $200 million risk contingency payment owed to two IOUs that have load reduction payments, and deferred the remaining $100 million payment and related interest to the fiscal years 2007 through 2011 period.

IOU Exchange Benefit amounts for the fiscal year 2007 through 2011 period cannot yet be calculated; however, the annual floor of $100 million has been recorded as a liability totaling $500 million. In addition, the IOU Risk Contingency Payment amounts that were deferred in fiscal year 2004 will be repaid $20 million per year (plus interest) during the fiscal year 2007 through 2011 period and have been recorded as a liability. The IOU Exchange Benefits recorded on the Balance Sheet at Sept. 30, 2005 includes $357 million for fiscal year 2006. The amounts to be collected through future rates are included in regulatory assets.

Further, it is possible that these agreements may be revised in connection with legal challenges that have been filed with the Ninth Circuit Court, which could result in a remand and potential changes to the IOU Exchange Benefit Amounts to be provided to the IOU customers. BPA believes it is likely that the agreements will be sustained and, as such, the annual floor.

7. Commitments and Contingencies

Purchase and Sales Commitments

Subscription contracts are the basis for the contractual relationship between BPA and nearly all of its firm power customers. 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 years and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through fiscal year 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 delivered.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2005.

Purchase Power and Sales Commitments

As of Sept. 30 — thousands of dollars

	Purchase	Sales
2006	$ 559,067	$ 2,095,743
2007	19,472	1,711,918
2008	18,847	1,723,573
2009	53,102	1,722,475
2010	53,102	1,806,711
2011	54,027	1,802,767
	$757,617	**$10,863,187**

Augmentation commitments run through 2006. Purchases and sales have not been adjusted for EITF 03-11 net basis reporting.

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 $739 thousand in fiscal year 2004. Future irrigation assistance payments ultimately could total $667 million and are scheduled over a maximum of 66 years. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2005.

Irrigation Assistance

As of Sept. 30 — thousands of dollars

Scheduled Distributions

2006	$ —
2007	—
2008	2,950
2009	6,590
2010	—
2011+	657,693
	$667,233

Excludes $56.6 million for Lower Teton, which was never completed, therefore never produced electricity and the administrator has no obligation to recover these costs.

Additional Post-Retirement Contributions

FCRPS makes additional annual contributions to the U.S. Treasury in order to ensure that all federal post-retirement benefit programs provided to its employees are fully funded and such costs are both recovered through rates and properly expensed. The additional contributions are based on employee plan participation and the extent to which the particular plans are under funded. BPA paid $26.5 million, $30.9 million and $35.1 million to the U.S. Treasury during fiscal years 2005, 2004 and 2003, respectively. These amounts were recorded as expense when paid. At Sept. 30, 2005, FCRPS has scheduled additional payments totaling $124 million as shown in the following table.

Additional Post-Retirement Contributions

As of Sept. 30 — thousands of dollars

Scheduled Contributions

2006	$ 23,200
2007	21,100
2008	18,000
2009*	30,554
2010*	31,195
	$ 124,049

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

* Estimates not currently scheduled.

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 $6.8 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $14.1 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.5 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $300 million, BPA could be subject to a retrospective assessment of up to $95.8 million limited to an annual maximum of $10 million. Assessments would be included in BPA's costs and recovered through rates.

Environmental Matters

From time to time, there are sites for which BPA, Corps or Reclamation has 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 rates.

Litigation

In the fall of 2002, two separate groups of BPA customers filed separate petitions with the Ninth Circuit Court relating to the contracts for the Slice Product (Slice Agreements). These petitions have been consolidated into a single proceeding along with a third petition filed in 2004. Under the Slice Agreements, BPA is to determine certain after-the-fact annual adjustments to the Slice power rate to reflect actual costs (True-up Charges). The principal petition was filed by Slice customers seeking to reverse $84 million in BPA-determined True-up Charges for fiscal year 2002. The Slice customer litigants assert that BPA's determination of the charges is not consistent with the Slice Agreements and that the Slice Agreements require binding arbitration of such disputes such that the Ninth Circuit Court lacks jurisdiction to resolve the correctness of BPA's determination of the charges. BPA and the other litigants are attempting to resolve the dispute through mediation while the litigation moves forward. BPA continues to maintain that the charges are consistent with the Slice Agreements. Depending on the result of the mediation, or alternatively the litigation pertaining to the 2002 True-up Charges, it is possible that True-up Charges with respect to fiscal years 2003 and thereafter could be adjusted.

The FCRPS is party to various other 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' financial position or results of operations.

Judgments and settlements are included in BPA's costs and recovered through rates.

8. Segments

BPA follows 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' major operating segments are defined by the utility functions of generation and transmission. In the following table, 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. "Other" represents items that are necessary to reconcile to the financial statements. These items generally include shared activity such as debt management actions and inter-business unit 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 BPA has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed. Unaffiliated revenues represent sales to external customers for each segment. Intersegment revenues are eliminated.

During fiscal years 2005, 2004 and 2003, no single customer represented 10 percent or more of the FCRPS' revenues.

Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Other	FCRPS
2005				
Unaffiliated revenues	**$ 2,740,700**	**$ 527,383**	**$ —**	**$3,268,083**
Intersegment revenues	**73,524**	**107,147**	**(180,671)**	**—**
Total operating revenues	**2,814,224**	**634,530**	**(180,671)**	**3,268,083**
Unaffiliated expenses	**2,025,938**	**260,060**	**(157,669)**	**2,128,329**
Depreciation	**186,099**	**189,501**	**—**	**375,600**
Intersegment expenses	**106,510**	**73,524**	**(180,034)**	**—**
Total operating expenses	**2,318,547**	**523,085**	**(337,703)**	**2,503,929**
Net operating revenues	**495,677**	**111,445**	**157,032**	**764,154**
Interest expense	**166,610**	**135,754**	**(25,080)**	**277,284**
Net revenues (expenses)	**$ 329,067**	**$ (24,309)**	**$ 182,112**	**$ 486,870**
2004				
Unaffiliated revenues	$ 2,661,975	$ 535,936	$ —	$3,197,911
Intersegment revenues	76,923	108,123	(185,046)	—
Total operating revenues	2,738,898	644,059	(185,046)	3,197,911
Unaffiliated expenses	1,971,620	252,738	(181,952)	2,042,406
Depreciation	177,297	188,942	—	366,239
Intersegment expenses	108,194	76,758	(184,952)	—
Total operating expenses	2,257,111	518,438	(366,904)	2,408,645
Net operating revenues	481,787	125,621	181,858	789,266
Interest expense	162,531	137,823	(15,503)	284,851
Net revenues (expenses)	$ 319,256	$ (12,202)	$ 197,361	$ 504,415
2003				
Unaffiliated revenues	$ 3,059,386	$ 552,718	$ —	$3,612,104
Intersegment revenues	85,425	110,884	(196,309)	—
Total operating revenues	3,144,811	663,602	(196,309)	3,612,104
Unaffiliated expenses	2,435,923	240,460	(315,320)	2,361,063
Depreciation	178,896	171,130	—	350,026
Intersegment expenses	110,401	85,788	(196,189)	—
Total operating expenses	2,725,220	497,378	(511,509)	2,711,089
Net operating revenues	419,591	166,224	315,200	901,015
Interest expense	176,595	168,996	—	345,591
Net revenues (expenses)	$ 242,996	$ (2,772)	$ 315,200	$ 555,424

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Federal Columbia River Power System

Combined Balance Sheets

(Unaudited)

		December 31, 2005		September 30, 2005
		(thousands of dollars)		
Assets				
Federal utility plant				
Completed plant	$	**12,797,101**	$	12,722,386
Accumulated depreciation		**(4,555,276)**		(4,453,745)
		8,241,825		8,268,641
Construction work in progress		**1,188,888**		1,152,978
Net federal utility plant		**9,430,713**		9,421,619
Nonfederal generation		**2,385,745**		2,389,445
Current assets				
Cash		**738,143**		651,740
Accounts receivable, net of allowance		**143,368**		88,184
Accrued unbilled revenues		**237,271**		208,801
Materials and supplies, at average cost		**75,904**		75,073
Prepaid expenses		**266,139**		321,032
Total current assets		**1,460,825**		1,344,830
Other assets				
Regulatory assets		**6,005,254**		5,509,596
Nonfederal nuclear decommissioning trusts		**129,008**		125,509
Deferred charges and other		**184,257**		234,773
Total other assets		**6,318,519**		5,869,878
Total assets	$	**19,595,802**	$	19,025,772
Capitalization and Liabilities				
Capitalization and long-term liabilities				
Accumulated net revenues	$	**1,466,551**	$	1,334,294
Federal appropriations		**4,300,429**		4,272,662
Bonds issued to U.S. Treasury		**2,171,800**		2,211,800
Nonfederal projects debt		**6,277,664**		6,286,559
Total capitalization and long-term liabilities		**14,216,444**		14,105,315
Commitments and contingencies (See Note 7 to annual financial statements)				
Current liabilities				
Federal appropriations		**68,939**		68,939
Bonds issued to U.S. Treasury		**515,000**		565,000
Nonfederal projects debt		**208,676**		207,490
Accounts payable and other current liabilities		**343,371**		322,497
Total current liabilities		**1,135,986**		1,163,926
Other Liabilities				
Regulatory liabilities		**2,115,170**		2,129,660
IOU exchange benefits		**1,494,496**		984,187
Nonfederal nuclear asset retirement obligations		**161,900**		160,600
Deferred credits		**471,806**		482,084
Total other liabilities		**4,243,372**		3,756,531
Total capitalization and liabilities	$	**19,595,802**	$	19,025,772

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

	Three Months Ended December 31, 2005	2004
	(thousands of dollars)	
Operating revenues		
Sales	**$ 818,931**	$ 747,551
SFAS 133 derivative mark-to-market	**(32,969)**	(8,826)
Miscellaneous revenues	**11,069**	11,916
U.S. Treasury credits for fish	**21,465**	17,338
Total operating revenues	**818,496**	767,979
Operating expenses		
Operations and maintenance	**290,475**	279,879
Purchased power	**156,283**	133,304
Nonfederal projects	**82,612**	83,987
Federal projects depreciation and amortization	**86,615**	89,845
Total operating expenses	**615,985**	587,015
Net operating revenues	**202,511**	180,964
Interest expense		
Interest on federal investment		
Appropriated funds	**48,052**	49,084
Bonds issued to U.S. Treasury	**26,943**	29,005
Allowance for funds used during construction	**(4,741)**	(6,598)
Net interest expense	**70,254**	71,491
Net revenues	**$ 132,257**	$ 109,473

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.

Report of Independent Auditors

To the Executive Board of Energy Northwest

We have audited the accompanying balance sheet of Energy Northwest and the related individual balance sheets of Energy Northwest's business units and internal service fund as of June 30, 2005, and the related statement of operations and fund equity and of cash flows for the year then ended. Energy Northwest's business units include the Columbia Generating Station, Packwood Lake Hydroelectric Project, Nuclear Project No. 1, Nuclear Project No. 3, the Business Development Fund, Grays Harbor Energy Facility, and the Nine Canyon Wind Project. These basic financial statements are the responsibility of Energy Northwest's management. Our responsibility is to express an opinion on these basic financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the basic financial statements are free from material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the basic financial statements referred to above present fairly, in all material respects, the financial position of Energy Northwest and Energy Northwest's business units and internal service fund as of June 30, 2005, and the results of their operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis listed in the table of contents is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

October 20, 2005

Portland, Oregon

Management's Discussion and Analysis

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington. Each Energy Northwest Business Unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by Business Unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the Fiscal Year ended June 30, 2005 with the basic financial statements for the Fiscal Year ended June 30, 2004. Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest applies GAAP to the extent it does not conflict with Governmental Accounting Standards Board (GASB) standards (see Note B to the Financial Statements).

The financial statements include the Balance Sheets; Statements of Operations and Fund Equity; Statements of Cash Flows; Supplementary Schedules of Outstanding Long-Term Debt and Debt Service Requirements; and Notes to Financial Statements for each of the Business Units. The Balance Sheets present the financial position of each Business Unit based on an accrual basis. The Balance Sheets report information about construction work in progress, amount of resources and obligations, restricted accounts and due to/due from balances (see Note B to the financial statements) that reflect what is owed by each Business Unit.

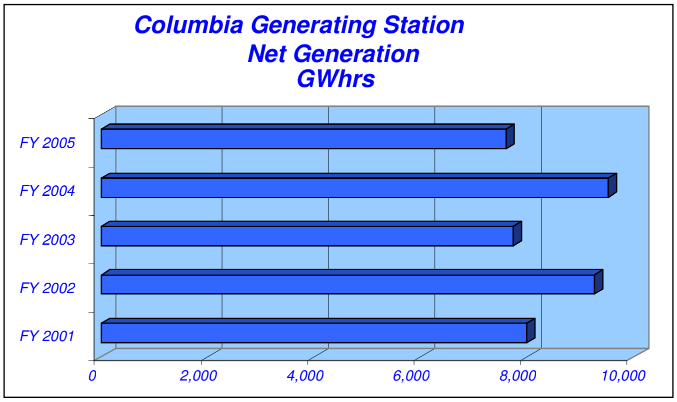
The Statements of Operations and Fund Equity reports information relating to all expenses, revenues and equity that reflect the results of each Business Unit and its related activities over the course of the Fiscal Year. The information provided aids in benchmarking activities, conducting comparisons to evaluate progress, and determining whether the Business Unit has successfully recovered its costs.

The Statements of Cash Flows reflects cash receipts and disbursements and net changes resulting from operating, financing and investment activities. The statements provide insight into what generates cash, where the cash comes from, and what it was used for.

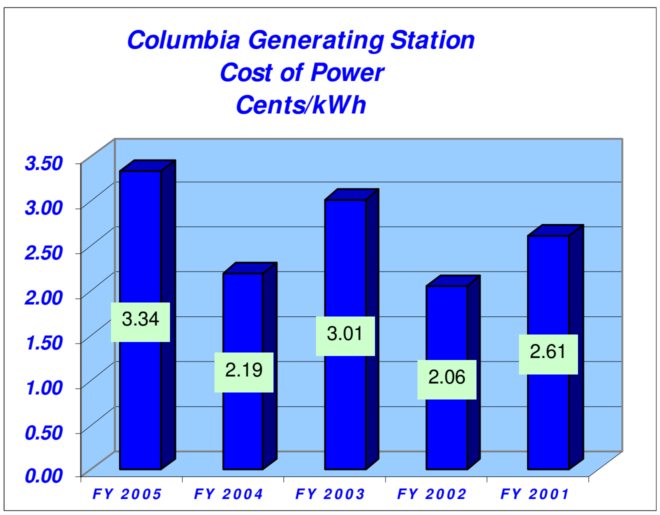
The Notes to Financial Statements present disclosures that contribute to the understanding of the material presented in the financial statements. This includes but is not limited to, accounting policies, significant balances and activities, materials risks, commitments and obligations and subsequent events, if applicable.

Columbia Generating Station

The Columbia Generating Station Nuclear Power Plant (Columbia) is owned by Energy Northwest and its Participants and operated by Energy Northwest. The Plant is a 1,153 megawatt (MWe) boiling water nuclear power station located on the Department of Energy's Hanford Reservation north of Richland, Washington. Columbia Generating Station (CGS) completed more than a year of continuous generation, setting a station record for operating a total of 393 days extending partially into Fiscal Year (FY) 2005 (July 3, 2003 to July 30, 2004). Columbia produced 7,599 GWh of electricity in FY 2005, as compared to 9,520 GWh of electricity in FY Year 2004, which included economic dispatch of 0 GWh and 16 GWh respectively. Columbia successfully completed its second two-year refueling and maintenance outage (R-17) in June of 2005. CGS completed R-17 within the 35 day budget with costs totaling $52.9 million. However there were three forced outages in FY 2005, in addition to the R-17 planned outage, that resulted in the decreased generation levels in FY 2005 from FY 2004 levels.



Energy Northwest's performance is measured in several ways, including cost of power at Columbia Generating Station. The industry cost of power fluctuates somewhat year to year depending on various factors such as refueling outages and other planned activities.



Balance Sheet Analysis

Increase to total Plant in Service and Construction Work In Progress (CWIP) from FY 2004 to FY 2005 was $24.4 million. The total increase was mostly a result of $15.9 million spent on the Nuclear Regulatory Commission (NRC) Mandated Security Project. The NRC, after the September 11, 2001 terrorist attacks, mandated heightened security improvements to all nuclear facilities. These improvements were substantially completed in 2005. Energy Northwest spent $10.3 million on this project in FY 2005 with a two year project cost of $15.9 million. Other major components of the change in plant and CWIP were upgrades to the Station Security System Computer, which runs all of the security systems inside the protected area of CGS ($5.4 million); Jet Pump Clamps, which modified seals to reduce fatigue and extend continued operation out 20 years past R-17 ($2.0 million).

Nuclear fuel, net of accumulated amortization, increased $24.1 million from FY 2004 to $126.1 million for FY 2005. During FY 2005, CGS purchased $51.0 million of nuclear fuel, which was offset by current year amortization of $26.9 million. The fuel purchases were associated with the R-18 and R-19 maintenance and refueling planned outages in FY 2007 and FY 2009.

The Restricted Assets Special Funds increased $65.7 million from FY 2004 levels to $117.2 million in FY 2005. This was due to additional financing for future fuel purchases associated with the two year refueling and maintenance outages and capital improvements. It is expected this increase will supply necessary funding for the next two refueling outages (R-18 and R-19 in FY 2007 and FY 2009). The increase in restricted assets was partially offset by the $19.4 million in Construction fund spending.

The Debt Service Funds increased $11.2 million in FY 2005 to $32.9 million. The increase was due to interest payable being larger in FY 2005 than in FY 2004.

Long-term receivables and current assets remained relatively stable from FY 2004 to FY 2005. The long term receivable account increased slightly due to an FY 2004 adjustment to a $3.3 million reclassification made for a 1992 Settlement Agreement with a third party. The estimate made in FY 2005 was in anticipation of the R-17 related discounts that would be forthcoming in the next year; however the amounts received in FY 2005 were lower than originally estimated.

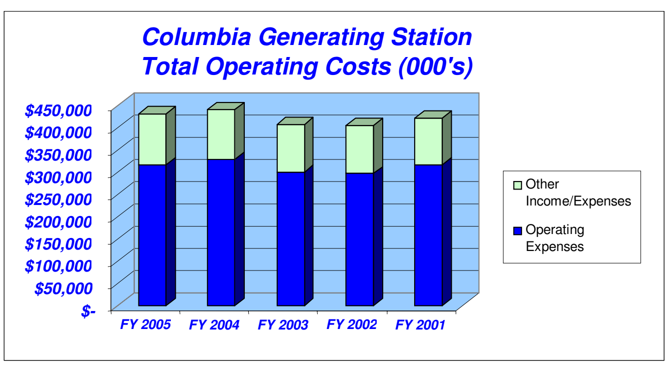
Costs in Excess of Billings have increased $69.3 million in FY 2005 from $494.3 million to $563.2 million, largely due to refunding current maturities while extending the overall maturities on the refunding debt. In addition, the accumulated decommissioning and site restoration accrued costs are not currently billed to Bonneville Power Administration (BPA). BPA holds and manages a trust fund for the purpose of funding decommissioning and site restoration (see Note B to the financial statements, Decommissioning and Site Restoration). The balances in these external trust funds are not reflected on Energy Northwest's Balance Sheet.

Long-Term Debt increased $217.6 million in FY 2005 from $2.05 billion to $2.27 billion, which was a result of the FY 2005 Bond Issue. As explained above, in FY 2005, new debt was issued for various CGS construction projects, fuel purchases, as well as being issued as part of the Debt Optimization Plan Debt (see Note E to the financial statements).

Statement of Operations Analysis

Columbia Generating Station is a net-billed Project. Energy Northwest recognizes revenues equal to expense for each period on net-billed projects. No net revenues or loss is recognized and no equity is accumulated.

As a whole, the operating revenues and expenses remained relatively the same from FY 2004 to FY 2005, with overall Operating Revenues needed to cover expenditures decreasing slightly from last year.



Four individual components of operating expenses related to the successful completion of R-17 and the three unplanned outages were:

- Nuclear Fuel—Decreased from $35.3 million in FY 2004 to $28.6 million in FY 2005;
- Fuel Disposal Fee—Decreased from $9.0 million in FY 2004 to $7.2 million in FY 2005;
- Generation tax—Decreased from $3.2 million in FY 2004 to $2.3 million in FY 2005;
- Operations and Maintenance—Increased from $129.6 million in FY 2004 to $178.7 million (see R-17 costs discussed above) in FY 2005;

The first three points were a result of lower generation while the fourth point was a result of increased wages due to R-17.

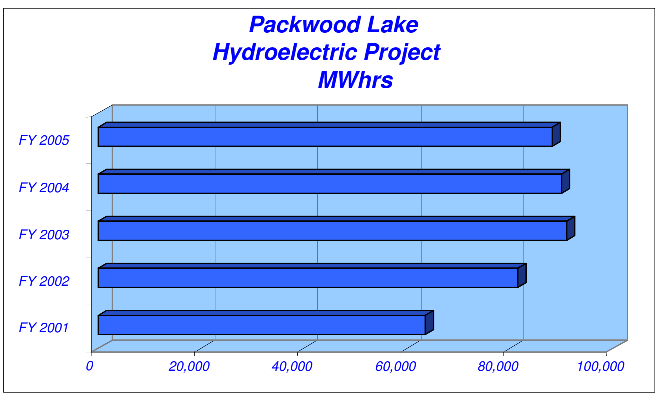
Other major changes in CGS operations were:

- Administrative & General—Decreased from $21.6 million to $18.6 million reflecting the continuing concerted effort to reduce overall costs for CGS;
- Decommissioning—Decreased from $43.0 million to $5.4 million because FY 2004 included an increase to the value of the Asset Retirement Obligation (ARO), which was offset by an increase to Cost in Excess of Billings in compliance with the Net Billing Agreement. The amount is a combination of probable cases for accomplishing the required retirement obligations and their associated probabilities. The liability will also be increased each year to account for the accretion value of the obligation. This yearly accretion value is the amount represented by the FY 2005 value of $4.8 million. (See Note G to the financial statements for further explanation).

Other Income and Expense changes are the net effects on Columbia Debt (see Note E to the financial statements). Investment Income was affected by favorable rates in FY 2005 resulting in an increase of $2.3 million from FY 2004 income to $4.2 million in FY 2005. Additionally, interest expense increased slightly in FY 2005 from $114.2 million to $116.3 million due to $461.7 million of new debt issued in FY 2004 at a 3.75% to 5.5% interest rate. Amortization of Bond Discount Expense and Amortization of Bond Refunding netted a decrease in expense of $1.9 as a result of the Bond Refunding issues.

Packwood Lake Hydroelectric Project

The Packwood Lake Hydroelectric Project is owned and operated by Energy Northwest. The Project consists of a dam at Packwood Lake and powerhouse 1800 feet below the dam that is located south of Packwood, Washington. Packwood produced 88.31 GWh of electricity in FY 2005 versus 90.03 GWh in FY 2004.



Balance Sheet Analysis

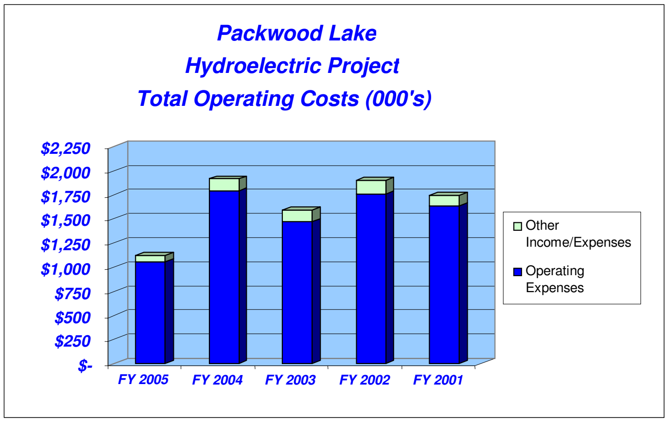
Current Assets have decreased $.3 million from $2.3 million in FY 2004 to $2.0 million in FY 2005. Majority of the decrease was due to timing of power sales. There were no significant changes to current liabilities other than a decrease in due to other business units of $649K from $682K in FY 2004 to $33K in FY 2005. No new debt was issued and the total debt continues to decrease per the current debt schedules. As a result of operations, Packwood accrued $338K in excess funding that has been agreed to by participants in October of 2005, to be returned to the Packwood business unit for FY 2006 operating reserves.

Packwood incurred $.6 million in re-licensing costs for FY 2005. These costs are shown as other deferred charges on the Balance Sheet. The FY 2006 projections are for an additional $.6 million in costs to continue the re-licensing efforts. The Federal Regulatory Commission (FERC) issued a 50-year operating license to Packwood on March 1, 1960. The current license will expire on February 28, 2010.

Statement of Operations Analysis

The agreement with Project Participants obligates them to pay annual costs and they receive excess revenues. Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized and no equity is accumulated. Revenues decreased because of the cost decreases detailed below:

- Total Operating Expenses decreased $.7 million, from $1.8 million in FY 2004 to $1.1 million in FY 2005. Major drivers for this change were:
  - Decrease to Depreciation and Amortization of $.3 million as the majority of the plant assets continue to become completely depreciated
  - Operations and Maintenance, along with Administrative and General expenditures, decreased $.4 million from $1.4 million in FY 2004 to $1.0 million in FY 2005. This was due to the decreased operations and maintenance costs due to insurance savings and completion of annual outage under budget.



Nuclear Project No. 1

Nuclear Project No. 1, a 1,250 MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 1. In FY 1999, the assets and liabilities of the Hanford Generating Project were consolidated into Nuclear Project No. 1. The Hanford Generating Project site restoration activities were completed on May 19, 2004. All funding requirements are net-billed obligations of Nuclear Project No. 1. Energy Northwest wholly owns Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity on Nuclear Project No. 1.

Balance Sheet Analysis

Under the debt optimization program, long-term debt increased $4.6 million from $1.961 billion in FY 2004 to $1.966 billion in FY 2005, due to debt restructuring to take advantage of lower interest rates.

Statement of Operations Analysis

Investment Income increased $1.2 million from $1.3 million in FY 2004 to $2.5 million in FY 2005, as rates of return began to increase from historical lows.

Nuclear Project No. 3

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

Balance Sheet Analysis

Under the debt optimization program, long-term debt was increased $24.7 million from $1.790 billion in FY 2004 to $1.814 million in FY 2005 due to debt restructuring to take advantage of lower interest rates.

Statement of Operations Analysis

Investment Income increased $1.0 million, from $0.9 million in FY 2004 to $1.9 million in FY 2005, as rates of return began to increase from historical lows.

Business Development Fund

The Business Development Fund (BDF) was created by Executive Board Resolution No. 1006 in April 1997, for the purpose of holding, administering, disbursing, and accounting for Energy Northwest costs and revenues generated from engaging in new energy business opportunities.

The BDF is managed as an enterprise fund. Three business sectors have been created within the fund: General Services, Generation, and Professional Services. Each sector may have one or more programs that are managed as a unique business activity. A fourth business sector, Business Unit Support, has been created to capture costs associated with developing programs.

Statement of Operations Analysis

Operating Revenues in FY 2005 totaled $8.1 million as compared to FY 2004 revenues of $14.7 million, a decrease of $6.6 million. The Department of Energy (DOE) and Energy Northwest had an agreement for the completion of restoration and cleanup of the Hanford Generating Project. Under the agreement DOE would be billed for 50% of the restoration and cleanup efforts. The project was completed in FY 2004 with Energy Northwest recognizing revenue of $3.8M. The reduction in intra-company business was the other driver to decreased revenues.

Total operating revenues decreased 45% in FY 2005; however net revenues for the FY 2005 showed a $697K loss as compared to a $987K loss in FY 2004.

Other Income and Expenses includes $2.4 million of Energy Business Services overhead that were credited to this account. The offset debit to this entry resides as an operating expense. Other income and expenses, less these overheads, was approximately $0.6 million.

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. Three of Energy Northwest's Research and Investigation business projects, BioEnergy Solutions, Wind Mining and Integrated Gasification Combined Cycle (IGCC), accounted for $1.1 million in expenditures with no revenues.

Energy BioEnergy Solutions is a business line of Energy Northwest that in FY 2005 worked on a full-scale biomass power test unit at a dairy farm near Pasco, Washington which was unable to meet expectations for biogas production. The business line is in the process of evaluating options for moving forward. In FY 2005, approximately $0.4 million was expended on developing this project.

Wind Mining efforts continued in FY 2005 with approximately $0.3 million being expended. These efforts are to explore, site and demonstrate wind resources for potential new wind sites.

Initial investigation into developing an Integrated Gasification Combined Cycle (IGCC) project was kicked off in FY 2005, with approximately $0.4 million expended. In July 2005, Energy Northwest's Board of Directors passed a resolution to pursue permitting and possible construction of an Integrated Gasification Combined Cycle (IGCC) power plant in western Washington. The proposal calls for a 600 MW power plant, designed to operate on a "synthesis gas" with regulated emissions similar to a natural gas plant. The clean-burning synthesis gas can be produced by gasifying rather than burning a variety of carbon-based feed stocks including petroleum coke and coal. Initial operation of the completed plant could be as early as 2011.

The Business Development Fund receives contributions from the Internal Service Fund to cover cash needs during this startup period. Initial startup costs are not expected to be paid back and are shown as contributions. As an operating business unit, requests can be made to fund incurred operating expenses. In FY 2005, the Business Development Fund received contributions (transfers) of $1.7 million.

Grays Harbor Energy Facility

The Grays Harbor Energy Facility Project was established in July 1990 to collect advances and contributions to pay the costs of investigating new generating projects, including the feasibility of a combustion turbine near Satsop, Washington. The project purpose was amended during FY 2002 to include the operation and maintenance of a gas fired combustion turbine placed on the Grays Harbor site (owned by Duke Energy Grays Harbor LLC) and included the option to purchase up to 50MW of power generated by the facility.

In September 2002, due to market conditions, Duke Energy North America (DENA) placed the project in “Construction Suspension.” In February 2004, DENA announced it has no intention to complete the facility with their own funds. Per the agreement with DENA, if construction was not restarted by August 31, 2004, such that the project reaches substantial completion eleven months later, or if the project fails to achieve commercial operation by December 31, 2005, Energy Northwest may request payment of approximately $5 million and dissolution of the O&M contract. Energy Northwest received this payment in March of 2005. Remaining cash and investments were transferred to the Internal Service Fund – Performance Fee Account in June of 2005. All obligations of this fund have been completed and the fund was dissolved by the Executive Board in July 2005.

Statement of Operations Analysis

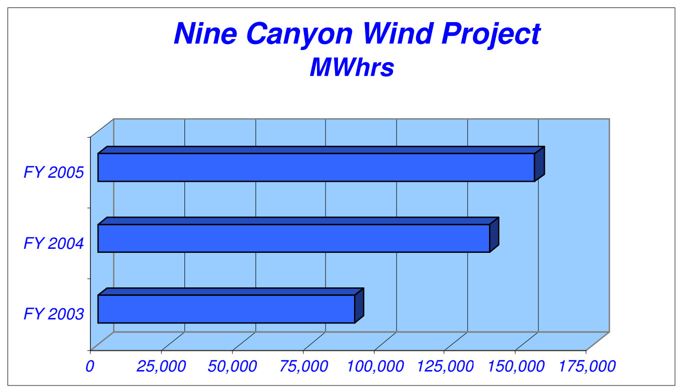
Non-Operating revenues were $0.4 million and $4.9 million for FY 2004 and FY 2005 respectively, with the increase due to the dissolution of O&M contract discussed above.

Nine Canyon Wind Project

The Nine Canyon Wind Energy Project is owned and operated by Energy Northwest. The Project is located in the Horse Heaven Hills area southwest of Kennewick, Washington. Electricity generated by the Project is purchased by Pacific Northwest Public Utility Districts whose customers have expressed an interest in purchasing at least a portion of their electricity from green power sources. Each purchaser of Phase I has signed a 22-year power purchase agreement with Energy Northwest and each purchaser of Phase II has signed a 20-year power purchase agreement. The project is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by the Benton County Public Utility District.

Phase I of the project, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 megawatts of electricity, for a total wind capacity of 48.1 megawatts. Phase II of the project, which was declared operational December 31, 2003, includes an additional 12 wind turbines with an aggregate generating capacity of approximately 15.6 megawatts. The total project generating capability is approximately 63.7 megawatts, which produces enough energy capacity for approximately 26,000 average homes.

Nine Canyon Wind Project produced 154.52 GWh of electricity in FY 2005 versus 138.44 GWh in FY 2004.



The turbines are installed in rows with about 500 feet between turbines. Each three-blade turbine consists of a tubular steel tower approximately 200 feet in height, three 100-foot turbine blades attached to a rotor, and a nacelle that houses a generator, gear box and braking mechanism.

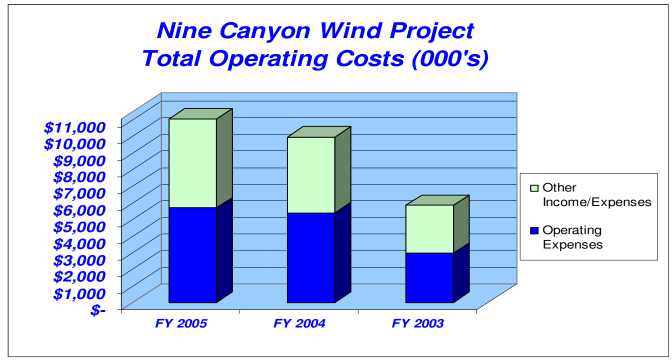
Balance Sheet Analysis

Receivables increased by $0.7 million corresponding to the increased size of the Renewable Energy Performance Incentive (REPI) payment accrued. The Fund Equity decreased by $2.7 million because the original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires in ten years. Reserves that were established are used to facilitate this plan. Long-term debt decreased by $3.6 million due to the effects of the refinancing of the Phase I debt in January 2005.

Statement of Operations Analysis

Operating Revenues increased $0.9M from $5.3M in FY 2004 to $6.2M in FY 2005. This was due to a full year of operation of Phase II of the project in FY 2005 as well as a planned billing increase to project participants of 3%. The project received revenue from the billing of the project purchasers at an average rate of $35.09 per MWh for FY 2005. Energy Northwest has accrued as income (contribution) from the DOE, REPI payments that enable the Nine Canyon Wind Project to receive funds based on generation as it applies to the REPI bill. The REPI was created as part of the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. The Nine Canyon Wind Project recorded a receivable for sixty-eight percent of the applied REPI funding in the amount of $2.3 million for FY 2005. The payment stream and the REPI receipts were projected to cover the total costs over the life of the purchase agreement. Permanent shortfalls in REPI funding will lead to increases in the billing of the Project participants in order to cover total Project costs.

The agreement with project purchasers anticipates a loss in FY 2006 with additional cash needs being paid from existing project reserve funds. The reserve funds were established so that the participant payments would increase at a rate of three percent per year over the life of each power purchaser agreement. Operating Costs are expended for debt service and for operational and maintenance items.



Internal Service Fund

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

Balance Sheet Analysis

The FY 2005 Balance Sheet increased $1.3 million from FY 2004. The net increase in Assets is primarily from a $0.5 million increase in Net Plant in Service and a $1.0 million increase in Current Assets. The net increase in Fund Equity and Liabilities is from a $4.9 million increase in Fund Equity offset by a $3.6 million decrease in Liabilities.

The increase in the Net Plant in Service is primarily due to the purchase of new Computer Equipment. The net change in Current Assets was a result of Interfund Transfers due to other Funds that are eliminated in the Combining of the Financial Statements and changes in cash and investment mix. The increase in

Fund Equity of $4.9 million is primarily due to dissolution and transfer of Grays Harbor business unit assets. The decrease in Current Liabilities is composed of a $.7 million increase in Accounts Payable offset by a $3.5 million decrease in Interfund Transfers due to other Funds that are eliminated in the Combining of the Financial Statements. The increase in Accounts Payable is primarily comprised of an increase in accrued costs, primarily related to contractor work incurred during R-17, but not paid by June 30, 2005.

Statement of Operations Analysis

Net Revenues for FY 2005 increased $0.1 million as rates of return on investments began to increase from historical lows.

BALANCE SHEETS

As of June 30, 2005 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2005 COMBINED TOTAL
ASSETS										
UTILITY PLANT (NOTE B)										
In service	$ 3,500,570	$ 12,991	$ -	$ -	$ 925	$ -	$ 68,486	$ 3,582,972	$ 46,029	$ 3,629,001
Not in service			25,253					25,253		25,253
Accumulated depreciation	(2,029,594)	(12,442)	(25,253)		(364)		(7,942)	(2,075,595)	(31,768)	(2,107,363)
	1,470,976	549	-	-	561	-	60,544	1,532,630	14,261	1,546,891
Nuclear fuel, net of accumulated amortization	126,143							126,143		126,143
Construction work in progress	36,784							36,784		36,784
	1,633,903	549	-	-	561	-	60,544	1,695,557	14,261	1,709,818
RESTRICTED ASSETS (NOTE B)										
Special funds										
Cash	17,393	1	180	313			1,806	19,693	1,468	21,161
Available-for-sale investments	99,804	285	12,367	12,073			1,645	126,174	1,254	127,428
Accounts and other receivables							2,299	2,299		2,299
Debt service funds										
Cash	32,187	8	37,160	19,087			100	88,542		88,542
Available-for-sale investments	701	743	8,469	9,192			6,455	25,560		25,560
	150,085	1,037	58,176	40,665	-	-	12,305	262,268	2,722	264,990
LONG-TERM RECEIVABLES (NOTE B)	3,527							3,527		3,527
CURRENT ASSETS										
Cash	89	1	535	25	363		464	1,477	3,070	4,547
Available-for-sale investments	4,629	1,691	5,939	5,575	305			18,139	27,589	45,728
Accounts and other receivables	1,583	218	34		1,659			3,494	76	3,570
Due from Participants	6		1					7		7
Due from other business units	4,555		17	133				4,705	780	
Due from other funds	16,353	13	9,728	9,717			149	35,960		
Materials and supplies	77,801						226	78,027		78,027
Prepayments and other	681	56			70			807	182	989
Nuclear fuel held for sale			1,095					1,095		1,095
	105,697	1,979	17,349	15,450	2,397		839	143,711	31,697	133,963
DEFERRED CHARGES										
Costs in excess of billings	563,566	643	1,948,519	1,784,811				4,297,539		4,297,539
Unamortized debt expense	15,063	1	14,275	11,986			1,961	43,286		43,286
Other deferred charges		638					4,894	5,532		5,532
	578,629	1,282	1,962,794	1,796,797	-	-	6,855	4,346,357	-	4,346,357
TOTAL ASSETS	$ 2,471,841	$ 4,847	$ 2,038,319	$ 1,852,912	$ 2,958	$ -	$ 80,543	$ 6,451,420	$ 48,680	$ 6,458,655

** Project recorded on a liquidation basis*

See notes to financial statements

BALANCE SHEETS *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2005 COMBINED TOTAL
FUND EQUITY AND LIABILITIES										
FUND EQUITY	$ -	$ -	$ -	$ -	$ 1,862	$ -	$ (8,245)	$ (6,383)	$ 11,835	$ 5,452
LONG-TERM DEBT (NOTE E)										
Revenue bonds payable	2,243,235	2,546	1,971,850	1,922,165			89,960	6,229,756		6,229,756
Unamortized discount							3,750	3,750		3,750
on bonds - net	69,928	(4)	52,097	(81,239)			(6,311)	34,471		34,471
Unamortized gain/(loss) on bond refundings	(41,148)	25	(58,073)	(26,753)				(125,949)		(125,949)
	2,272,015	2,567	1,965,874	1,814,173	-	-	87,399	6,142,028	-	6,142,028
LIABILITIES- PAYABLE FROM RESTRICTED ASSETS (NOTE B)										
Special funds										
Accounts payable and accrued expenses	97,130		13,307				529	110,966	1,807	112,773
Due to other funds	15,976	6	9,370	9,076			149	34,577		
Other deferred credits			1,275		185			1,460		1,460
Debt service funds										
Accrued interest payable	32,512	39	45,272	27,638				105,461		105,461
Due to other funds	377	7	358	641				1,383		
	145,995	52	69,582	37,355	185	-	678	253,847	1,807	219,694
OTHER NONCURRENT LIABILITIES	25,659							25,659		25,659
CURRENT LIABILITIES										
Current maturities of long-term debt		615						615		615
Accounts payable and accrued expenses	22,111	101	1,086	190	854		20	24,362	29,426	53,788
Due to Participants	6,061	1,479	1,777	1,194				10,511		10,511
Due to other business units		33			57		691	781	4,704	
	28,172	2,228	2,863	1,384	911		711	36,269	34,130	64,914
DEFERRED CREDITS										
Advances from Members and others									1	1
Other deferred credits									907	907
	-	-	-	-	-		-		908	908
TOTAL LIABILITIES	2,471,841	4,847	2,038,319	1,852,912	1,096		88,788	6,457,803	36,845	6,453,203
TOTAL FUND EQUITY AND LIABILITIES	$ 2,471,841	$ 4,847	$ 2,038,319	$ 1,852,912	$ 2,958	$ -	$ 80,543	$ 6,451,420	$ 48,680	$ 6,458,655

** Project recorded on a liquidation basis*

See notes to financial statements

STATEMENTS OF OPERATIONS AND FUND EQUITY

For the year ended June 30, 2005 (Dollars in Thousands)

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	SUBTOTAL	INTERNAL SERVICE FUND	2005 COMBINED TOTAL
OPERATING REVENUES	$ 430,570	$ 1,121	$	$	$ 8,099	$	$ 6,178	$ 445,968	$ -	$ 446,162
OPERATING EXPENSES										
Services to other business units										
Nuclear fuel	28,570							28,570		28,570
Spent fuel disposal fee	7,241							7,241		7,241
Decommissioning	5,397						58	5,455		5,455
Depreciation and amortization	76,866	28			229		3,569	80,692		80,692
Operations and maintenance	178,659	825			10,429		1,987	191,900		191,900
Administrative & general	18,637	185					28	18,850		18,850
Generation tax	2,315	19					33	2,367		2,367
Total operating expenses	317,685	1,057	-	-	10,658	-	5,675	335,075		335,075
NET OPERATING REVENUES(EXPENSES)	112,885	64	-	-	(2,559)	-	503	110,893		111,087
OTHER INCOME & EXPENSE										
Non-operating revenues			94,316	89,962		4,927		189,205	53,741	189,205
Investment income	4,160	64	2,453	1,938	99	50	295	9,059	197	9,059
Gain on bond redemption		4						4		4
Interest expense and discount amortization	(116,306)	(132)	(104,995)	(89,766)			(5,644)	(316,843)		(316,843)
Plant preservation and termination costs			(9,331)	(2,134)				(11,465)		(11,465)
Depreciation and amortization	(3,500)		(14)			25		(3,489)	(1,507)	(3,489)
Revaluation of Site Restoration			12,866					12,866		12,866
Services to other business units									(52,237)	
Other	2,761		4,705		1,763	(187)		9,042	0	9,042
NET REVENUES(EXPENSES)	-	-	-	-	(697)	4,815	(4,846)	(728)	194	(534)
Distribution & Contributions+A4	-	-	-	-	1,995	(6,171)	2,124	(2,052)	4,660	2,608
Beginning Fund Equity	-	-	-	-	564	1,356	(5,523)	(3,603)	6,981	3,378
ENDING FUND EQUITY	$ -	$ -	$ -	$ -	$ 1,862	$ -	$ (8,245)	$ (6,383)	$ 11,835	$ 5,452

** Project recorded on a liquidation basis*

See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 2005 *(Dollars in Thousands)*

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	INTERNAL SERVICE FUND	2005 COMBINED TOTAL
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES									
Operating revenue receipts	$ 360,724	$ 2,895	$ -	$ -	$ 5,194	$ -	$ 5,980	$ -	$ 374,793
Cash payments for operating expenses	(204,911)	(1,626)			(8,134)		162		(214,509)
Non-operating revenue receipts			101,919	73,968		5,088			180,975
Cash payments for preservation, termination expense			(31,266)	(15,312)					(46,578)
Cash payments for services						(1,441)		209	(1,232)
Cash payments for new business									0
Receipts (payments) for grants/contributions						(4,864)		4,864	0
Net cash provided (used) by operating and other activities	155,813	1,269	70,653	58,656	(2,940)	(1,217)	6,142	5,073	293,449
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES									
Proceeds from bond refundings	218,784		80,317	143,011			65,581		507,693
Refunded bond escrow requirement	(127,148)		(80,836)	(142,618)			(64,014)		(414,616)
Payment for bond issuance and financing costs	(2,177)		(677)	(1,010)			(1,135)		(4,999)
Capital and nuclear fuel acquisitions	(73,055)	(638)			(43)		1		(73,735)
Interest paid on revenue bonds	(97,788)	(137)	(97,349)	(62,111)			(6,867)		(264,252)
Principal paid on revenue bond maturities		(590)					(3,290)		(3,880)
Interest paid on Notes	(1,371)		(663)	(892)					(2,926)
Notes Payable							(165)		(165)
Construction Work in Progress							(2,060)		(2,060)
Net cash provided (used) by capital and related financing activities	(82,755)	(1,365)	(99,208)	(63,620)	(43)	-	(11,949)	-	(258,940)
CASH FLOWS FROM INVESTING ACTIVITIES									
Purchases of investment securities	(1,285,492)	(9,720)	(556,245)	(412,852)	(36,170)	(9,925)	(58,685)	(136,301)	(2,505,390)
Sales of investment securities	1,221,104	9,806	583,591	415,375	39,413	11,060	62,075	131,792	2,474,216
Interest on investments	4,287	47	2,508	1,931	102	51	264	476	9,666
Receipts from sales of plant assets			6,115						6,115
Net cash provided (used) by investing activities	(60,101)	133	35,969	4,454	3,345	1,186	3,654	(4,033)	(15,393)
NET INCREASE(DECREASE) IN CASH	12,957	37	7,414	(510)	362	(31)	(2,153)	1,040	19,116
CASH AT JUNE 30, 2004	36,712	(27)	30,461	19,935	1	31	4,523	3,498	95,134
CASH AT JUNE 30, 2005 (NOTE B)	$ 49,669	$ 10	$ 37,875	$ 19,425	$ 363	$ -	$ 2,370	$ 4,538	$ 114,250

* *Project recorded on a liquidation basis*

See notes to financial statements

STATEMENTS OF CASH FLOWS *(Continued)*

For the year ended June 30, 2005 *(Dollars in Thousands)*

	COLUMBIA GENERATING STATION	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 *	NUCLEAR PROJECT NO.3 *	BUSINESS DEVELOPMENT FUND	GRAYS HARBOR ENERGY FACILITY	NINE CANYON WIND PROJECT	INTERNAL SERVICE FUND	2005 COMBINED TOTAL
RECONCILIATION OF OPERATING INCOME TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITES									
Net operating revenues (expenses)	$ 112,885	$ 64	$ -	$ -	$ (2,559)	$ -	$ 503	$ -	$ 110,893
Adjustments to reconcile net operating revenues to cash provided by operating activities:									
Depreciation and amortization	103,765	25			118		3,560		107,468
Decommissioning	5,398						58		5,456
Other	3,251	638			1,763		(270)		5,382
Change in operating assets and liabilities:									
Deferred charges/costs in excess of billings	(69,516)	(23)							(69,539)
Accounts receivable	2,646	237			409		1,537		4,829
Materials and supplies	(6,320)								(6,320)
Prepaid and other assets	(254)	2			24		(1)		(229)
Due from/to other business units, funds and Participants	3,125	286			(2,886)		860		1,385
Accounts payable	833	40			191		(105)		959
Non-operating revenue receipts			101,919	73,968		5,088			180,975
Cash payments for preservation, termination expense			(31,266)	(15,312)					(46,578)
Cash payments for services						(1,441)		209	(1,232)
Receipts (payments) for grants/contributions						(4,864)		4,864	0
Net cash provided(used) by operating and other activities	$ 155,813	$ 1,269	$ 70,653	$ 58,656	$ (2,940)	$ (1,217)	$ 6,142	$ 5,073	$ 293,449

* *Project recorded on a liquidation basis*

See notes to financial statements

OUTSTANDING LONG-TERM DEBT

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
COLUMBIA GENERATING STATION REFUNDING REVENUE BONDS			
1990A	7.25	7-1-2006	$ 2,115
			2,115
1991A	(A)	7-1-06/2007	10,267
			10,267
1992A	6.10	7-1-2006	11,345
	6.30	7-1-2012	50,000
			61,345
1993A	5.70-5.80	7-1-06/2008	36,490
			36,490
1993B	5.50-5.65	7-1-06/2008	39,330
			39,330
1994A	4.80-6.00	7-1-06/2007	89,950
	(A)	7-1-2009	4,776
	5.40	7-1-2012	100,200
			194,926
1996A	5.60-6.00	7-1-06/2012	165,635
			165,635
1997A	5.10-5.20	7-1-10/2012	50,355
			50,355
1997B	5.00-5.50	7-1-06/2011	20,000
			20,000
1998A	5.00-5.75	7-1-06/2012	161,785
			161,785
2001A	5.00-5.50	7-1-13/2017	186,600
			186,600
2001B	5.50	7-1-2018	48,000
			48,000
2002A	5.20-5.75	7-1-17/2018	157,260
			157,260
2002B	5.35-6.00	7-1-2018	123,815
			123,815

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
COLUMBIA GENERATING STATION REFUNDING REVENUE BONDS (Continued)			
2003A	5.50	7-1-10/2015	$ 154,490
			154,490
2003B	4.15	7-1-2009	4,530
			4,530
2003F	5.00-5.25	7-1-07/2018	41,330
			41,330
2004A	3.75-5.25	7-1-08/2018	422,350
			422,350
2004B	5.50	7-1-2013	12,715
			12,715
2004C	5.25	7-1-07/2018	26,620
			26,620
2005A	5.00	7-1-15/2018	114,985
			114,985
2005B	4.11	7-1-2008	1,600
			1,600
2005C	4.34-4.74	7-1-9/2015	91,890
			91,890
1997-2A-1	VARIABLE		45,045
			45,045
1997-2A-2	VARIABLE		45,040
			45,040
Compound interest bonds accretion			24,717
Revenue bonds payable			$ 2,243,235
Estimated fair value at June 30, 2005			$ 2,222,214 (B)

(A) Compound Interest Bonds

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
PACKWOOD LAKE PROJECT REVENUE BONDS				
1962	3.625	3-1-2012	$ 2,271	
1965	3.75	3-1-2012	890	
Revenue ponds payable			$ 3,161	
Estimated Fair Value at June 30, 2005			$ 3,222	(B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO.1 REFUNDING REVENUE BONDS				
1989B	7.125	7-1-2016	$ 41,070	
			41,070	
1990B	7.25	7-1-2009	3,590	
			3,590	
1993A	7.00	7-1-07/2008	15,325	
			15,325	
1993B	5.60-7.00	7-1-07/2009	25,570	
			25,570	
1993C	5.00-5.20	7-1-06/2008	5,675	
			5,675	
1996A	5.70-6.00	7-1-06/2012	291,745	
			291,745	
1996C	5.20-6.00	7-1-06/2015	70,840	
	5.50	7-1-2017	24,860	
			95,700	
1997A	6.00	7-1-06/2008	20,400	
			20,400	
1997B	5.00-5.125	7-1-06/2017	242,465	
			242,465	
1998A	5.00-5.75	7-1-06/2017	78,650	
			78,650	
2001A	4.125-5.50	7-1-07/2013	77,160	
			77,160	
2001B	5.50	7-1-2017	23,600	(C)
			23,600	

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO.1 REFUNDING REVENUE BONDS (Continued)			
2002A	5.50-5.75	7-1-13/2017	$ 248,485
			248,485
2002B	6.00	7-1-2017	101,950
			101,950
2003A	5.50	7-1-13/2017	241,455
			241,455
2003B	4.06	7-1-2009	18,210
			18,210
2004A	5.25	7-1-2013	62,485
			62,485
2004B	5.50	7-1-2013	1,135
			1,135
2005A	5.00	7-1-13/2015	72,175
			72,175
2005B	4.11	7-1-2008	925
			925
1993-1A-1	VARIABLE		44,505
			44,505
1993-1A-2	VARIABLE		44,505
			44,505
1993-1A-3	VARIABLE		14,585
			14,585
2003-C-1	VARIABLE		50,235
			50,235
2003-C-2	VARIABLE		50,000
			50,000
2003-C-3	VARIABLE		50,250
			50,250
2003-C-4	VARIABLE		50,000
			50,000
Revenue bonds payable			$ 1,971,850
Estimated fair value at June 30, 2005			$ 2,141,322 (B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

(C) Auction Rate Certificates that will have a rate of 5.50 through 7/1/2008 and a variable rate thereafter until 7/1/2017

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO.3 REFUNDING REVENUE BONDS			
1989A	(A)	7-1-07/2014	$ 13,057
			13,057
1989B	(A)	7-1-07/2014	44,772
	7.125	7-1-2016	76,145
			120,917
1990B	(A)	7-1-07/2010	11,650
			11,650
1993B	5.60-7.00	7-1-07/2009	34,215
			34,215
1993C	5.00-7.50	7-1-06/2008	51,570
	(A)	7-1-13/2018	23,963
			75,533
1996A	5.50-6.00	7-1-06/2009	30,080
			30,080
1997A	5.00-6.00	7-1-06/2018	106,620
			106,620
1998A	5.125	7-1-2018	53,825
			53,825
2001A	5.50	7-1-10/2018	151,380
			151,380
2001B	5.50	7-01-2018	10,675
			10,675
2002B	6.00	7-01-2016	75,360
			75,360
2003A	5.50	7-1-11/2017	241,915
			241,915
2003B	4.15	7-1-2009	21,575
			21,575
2004A	5.25	7-1-14/2016	83,835
			83,835
2004B	5.50	7-1-2013	1,515
			1,515
2005A	5.00	7-1-13/2015	129,265
			129,265
2005B	4.11	7-1-2008	1,060
			1,060

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2005 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO.3 REFUNDING REVENUE BONDS (Continued)				
1993-3A-3	VARIABLE		$ 20,345	
			20,345	
1998-3A	VARIABLE		132,650	
			132,650	
2001B-3-1	VARIABLE		5,000	(C)
			5,000	
2001B-3-2	VARIABLE		10,000	(C)
			10,000	
2003D-1	VARIABLE		100,665	
			100,665	
2003D-2	VARIABLE		100,400	
			100,400	
2003E	VARIABLE		98,025	
			98,025	
Compound interest bonds accretion			292,603	
Revenue bonds payable			$ 1,922,165	
Estimated fair value at June 30, 2005			$ 1,975,474	(B)

(A) Compound Interest Bonds

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

(C) Auction Rate Certificates that will have a rate of 5.50 through 7/1/2010 and a variable rate thereafter until 7/1/2018

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NINE CANYON WIND PROJECT REVENUE BONDS				
2001A	4.55-4.95	7-1-06/2008	$ 5,035	
2001B	4.55-4.95	7-1-06/2008	2,025	
			7,060	
2003	3.00-5.00	7-1-06/2023	20,950	
			20,950	
2005	4.00-5.00	7-1-06/2023	61,950	
			61,950	
Revenue bond payable			$ 89,960	
Estimated fair value at June 30, 2005			$ 100,029	(B)

(B) The estimated fair value shown has been reported to meet the disclosure requirements of the Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled.

REVENUE BONDS PAYABLE	$ 6,230,371	
TOTAL ALL PROJECTS EST. FAIR VALUE	$ 6,442,261	

DEBT SERVICE REQUIREMENTS

As of June 30, 2005 (Dollars in Thousands)

COLUMBIA GENERATING STATION

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2005 Balance:*	$ -	$ 31,735	$ 31,735
2006	94,046	129,994	224,040
2007	153,686	118,866	272,552
2008	144,905	103,983	248,888
2009	146,201	102,564	248,765
2010	233,335	89,041	322,376
2011-2015	787,300	288,068	1,075,368
2016-2018	659,045	93,031	752,076
*Adjustment ** *	24,717	(24,717)	-
	$ 2,243,235	$ 932,565	$ 3,175,800

* Principal and Interest due July 1, 2005.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

PACKWOOD LAKE HYDROELECTRIC PROJECT

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2005 Balance:*	$ 205	$ 39	$ 244
2006	623	108	731
2007	648	85	733
2008	674	62	736
2009	572	37	609
2010	274	16	290
2011-2012	165	8	173
*Adjustment ** *			0
	$ 3,161	$ 355	$ 3,516

* Principal and Interest due July 1, 2005.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

NUCLEAR PROJECT NO. 1

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2005 Balance:*	$ -	$ 44,597	$ 44,597
2006	55,825	103,120	158,945
2007	64,575	99,615	164,190
2008	79,925	95,944	175,869
2009	86,710	91,160	177,870
2010	80,455	86,490	166,945
2011-2015	846,535	332,706	1,179,241
2016-2018	757,825	59,601	817,426
*Adjustment ** *			
	$ 1,971,850	$ 913,233	$ 2,885,083

* Principal and Interest due July 1, 2005.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

NUCLEAR PROJECT NO. 3

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2005 Balance:*	$ -	$ 26,391	$ 26,391
2006	42,275	76,065	118,340
2007	60,176	104,627	164,803
2008	64,390	101,635	166,025
2009	68,433	100,937	169,370
2010	38,862	98,828	137,690
2011-2015	521,085	402,307	923,392
2016-2018	834,341	112,604	946,945
*Adjustment ** *	292,603	(292,603)	-
	$ 1,922,165	$ 730,791	$ 2,652,956

* Principal and Interest due July 1, 2005.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

NINE CANYON WIND PROJECT

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2005 Balance:*	$ -	$ -	$ -
2006	3,240	4,247	7,487
2007	3,380	4,113	7,493
2008	4,315	3,968	8,283
2009	3,705	3,772	7,477
2010	3,885	3,596	7,481
2011-2015	22,455	15,011	37,466
2016-2020	28,390	9,198	37,588
2021-2023	20,590	2,080	22,670
*Adjustment ** *			
	$ 89,960	$ 45,985	$ 135,945

* Principal and Interest due July 1, 2005.

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

Notes to Financial Statements

NOTE A - GENERAL

Organization

Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, was organized in 1957. It is empowered to finance, acquire, construct and operate facilities for the generation and transmission of electric power. On June 30, 2005, its membership consisted of 16 public utility districts and 3 cities, Richland, Seattle and Tacoma. All members own and operate electric systems within the State of Washington. Energy Northwest is exempt from federal income tax. Energy Northwest has no taxing authority.

Energy Northwest Business Units

Each Energy Northwest Business Unit is financed and accounted for separate from all other current or future Business Units.

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

Energy Northwest operates the Columbia Generating Station, a 1,153 MWe (Design Electric Rating, net) generating plant completed in 1984. Energy Northwest has obtained all permits and licenses required to operate Columbia, including a Nuclear Regulatory Commission (NRC) operating license that expires in December 2023.

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5 MWe generating plant completed in 1964. Packwood operates under a fifty-year license from the Federal Energy Regulatory Commission (FERC) that expires on February 28, 2010. The electric power produced by Packwood is sold to 12 utilities, which pay the costs of Packwood, including the debt service on the Packwood Lake Hydroelectric revenue bonds. The Packwood Participants are obligated to pay annual costs of the Project including debt service, whether or not the Project is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of the bond resolution. The Participants share Project revenue as well.

Nuclear Project No. 1, a 1,250 MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. Nuclear Project No. 3, a 1,240 MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3 (see Note F - Nuclear Projects Nos. 1 and 3 Termination). All funding requirements are net-billed obligations of Nuclear Project No. 1. Energy Northwest wholly owns Nuclear Project No. 1.

Energy Northwest also manages the Business Development Fund and the Nine Canyon Wind Project, and managed the Grays Harbor Energy Facility Project:

- The Business Development Fund was established in April 1997 to pursue and develop new energy-related business opportunities.
- The Nine Canyon Wind Project was established in January 2001 for the purpose of exploring and establishing a wind energy project. Phase I of the project was completed in FY 2003. Phase I of the project consists of turbines which are rated at 48 MWe. Phase II of the project was declared operational December 31, 2003. Phase II of the project consists of turbines which are rated at 15.6 MWe. The total project generating capability is approximately 64 MWe.
- The Grays Harbor Energy Facility Project was established in July 1990 to collect advances and contributions to pay the costs of investigating new generating projects, including the feasibility of a combustion turbine near Satsop, Washington. The project purpose was amended during FY 2002 to include the operation and maintenance of a gas fired combustion turbine placed on the Grays Harbor site (owned by Duke Energy Grays Harbor LLC) and included the option to purchase up to 50MW of power generated by the facility. In September 2002, due to market conditions, Duke Energy North America (DENA) placed the project in "Construction Suspension." In February 2004, DENA announced it has no intention to complete the facility with its own funds. All obligations of this business unit have been completed and the fund was dissolved, effective June 30, by the Executive Board in July 2005.

The Internal Service Fund (formerly General Fund) was established in May 1957. It is currently used to account for the central procurement of certain common goods and services for the Business Units on a cost reimbursement basis.

The fund balances (net assets) for Business Development, Nine Canyon Wind Project and the Internal Service Fund includes (in thousands): invested in capital assets, net of related debt, $561, ($24,894) and $14,261, restricted assets of $0, $12,305, $2,722; and unrestricted assets (deficit) of $1,301, $4,344, and ($5,148), respectively.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest applies GAAP to the extent it does not conflict with Governmental Accounting Standards Board (GASB) standards (see Note B to the financial statements). Accounts are maintained in accordance with the uniform system of accounts of the Federal Energy Regulatory Commission (FERC). Separate funds and books of account are maintained for each Business Unit. Payment of obligations of one Business Unit with funds of another Business Unit is prohibited, and would constitute violation of bond resolution covenants.

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

Liabilities of the Internal Service Fund represent accrued payroll, vacation pay, employee benefits, and common accounts payable which have been charged directly or indirectly to Business Units and will be funded by the Business Units when paid. Net amounts owed to or receivable from Energy Northwest Business Units are recorded under Current Liabilities – Due to other Business Units, or Current Assets – Due from other Business Units on the Internal Service Fund Balance Sheet.

The Combined Total column on the financial statements is for presentation only as each Energy Northwest Business Unit is financed and accounted for separately from all other current and future Business Units. The Fiscal Year (FY) 2005 Combined Total includes eliminations for transactions between Business Units as required in Statement No. 34, “Basic Financial Statements and Management’s Discussion and Analysis for State and Local Governments” of the Governmental Accounting Standards Board (GASB).

Pursuant to GASB Statement No. 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," Energy Northwest has elected to apply all Financial Accounting Standards Board statements and interpretations, except for those that conflict with or contradict GASB pronouncements. Specifically, Statement of Governmental Accounting Standard No. 7 “Advance Refundings Resulting in Defeasance of Debt” and No. 23 “Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities” conflict with Statement of Financial Accounting Standard (SFAS) No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.” As such, the guidance under Statement of Governmental Accounting Standard No. 7 and No. 23 is followed. Such guidance governs the accounting for bond defeasances and refundings.

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

Energy Northwest’s fiscal year begins on July 1st and ends on June 30th.

Utility Plant

Utility plant is stated at original cost. Plant in service is depreciated by the straight-line method over the estimated useful lives of the various classes of plant, which range from five to 60 years.

During the normal construction phase of a Capital Facility, Energy Northwest’s policy is to capitalize all costs relating to the Project, including interest expense, related administrative and general expense, less any interest income earned.

The utility plant and net assets of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in FY 1995 and was included in Cost in Excess of Billings. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 1 and 3 have been charged to operations. Utility Plant activity for the year ended June 30, 2005, was as follows:

Utility Plant Activity *(Amount in Thousands)*

	BEGINNING BALANCE	INCREASES	DECREASES	ENDING BALANCE
Columbia				
Generation	$ 3,451,357	$ 16,744	$ -	$ 3,468,101
Decommission	31,110	1,359	-	32,469
Construction Work-in-Progress	30,501	21,869	(15,586)	36,784
Accumulated Depreciation	(1,943,130)	(75,504)	-	(2,018,634)
Accumulated Amortization	(10,380)	(580)	-	(10,960)
Utility Plant net	$ 1,559,458	$ (36,112)	$ (15,586)	$ 1,507,760
Nine Canyon				
Generation	$ 68,036	$ 1	$ -	$ 68,037
Decommission	449	-	-	449
Construction Work-in-Progress	-	1	(1)	-
Accumulated Depreciation	(4,578)	(3,305)	-	(7,883)
Accumulated Amortization	(37)	(22)	-	(59)
Utility Plant net	$ 63,870	$ (3,325)	$ (1)	$ 60,544
Packwood				
Generation	$ 12,991	$ -	$ -	$ 12,991
Accumulated Depreciation	(12,417)	(25)	-	(12,442)
Utility Plant net	$ 574	$ (25)	$ -	$ 549
Business Development				
Generation	$ 882	$ 43	$ -	$ 925
Construction Work-in-Progress	-	43	(43)	-
Accumulated Depreciation	(246)	(118)	-	(364)
Utility Plant net	$ 636	$ (32)	$ (43)	$ 561
Internal Service Fund				
Generation	$ 43,837	$ 1,783	$ -	$ 45,620
Construction Work-in-Progress	515	409	(515)	409
Accumulated Depreciation	(30,606)	(1,162)	-	(31,768)
Utility Plant net	$ 13,746	$ 1,030	$ (515)	$ 14,261

Nuclear Fuel

All expenditures related to the initial purchase of nuclear fuel for Columbia, including interest, were capitalized and carried at cost. When the fuel is placed in the reactor, the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. Accumulated nuclear fuel amortization (the amortization of the cost of nuclear fuel assemblies in the reactor used in the production of energy and in the fuel pool for less than six months per FERC guidelines) is $161.1 million as of June 30, 2005 for Columbia.

Energy Northwest has a contract with the Department of Energy (DOE) that requires the DOE to accept title and dispose of spent nuclear fuel. Although the courts have ruled that the DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, the repository is not expected to be in operation before 2010. The current period operating expense for Columbia includes a $7.2 million charge from the DOE for future spent nuclear fuel storage and disposal in accordance with the Nuclear Waste Policy Act of 1982.

Energy Northwest has completed a Project to store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. Spent Fuel will be transferred from the Spent Fuel pool to the Independent Spent Fuel Storage Installation (ISFSI) periodically to allow for future refuelings. Current period operating costs include $27.2 million for nuclear fuel and $1.4 million accrued liability for future dry cask storage costs.

Restricted Assets

In accordance with Project bond resolutions, related agreements or state law, separate restricted funds have been established for each Business Unit. The assets held in these funds are restricted for specific uses including construction, debt service, capital additions, extraordinary operation and maintenance costs, termination, decommissioning, hazardous waste disposal, and workers' compensation claims.

Long-Term Receivables

Long-term receivables include minimum guaranteed amounts adjusted annually pertaining to future discounts for certain goods and services to be provided to Columbia as the result of a litigation settlement and subsequent revisions.

Accounts and Other Receivables

Accounts and other receivables for the Internal Service Fund include miscellaneous receivables outstanding from other Business Units that have not yet been collected. The amounts due to each Business Unit are reflected in the due to/from other Business Units account. Accounts and other receivables specific to each Business Unit are recorded in the residing Business Unit.

Asset Retirement Obligation

Energy Northwest adopted the Statement of Financial Accounting Standards No. 143, Accounting for Obligations Associated with the Retirement of Long-Lived Asset (SFAS 143) on July 1, 2002. SFAS 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation (ARO), such as nuclear decommissioning and site restoration liabilities, in the period in which it is incurred, rather than using a cost-accumulation approach. See Note G, Accounting Change for Asset Retirement Obligations.

Decommissioning and Site Restoration

Energy Northwest established decommissioning and site restoration funds for Columbia and monies are being deposited each year in accordance with an established funding plan.

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on decommissioning the plants at the end of each plant's operating life. In September 1998, the NRC approved and published its "Final Rule on Financial Assurance Requirements for Decommissioning Power Reactors." As provided in this rule, each power reactor licensee is required to report to the NRC the status of its decommissioning funding for each reactor or share of a reactor it owns. This reporting requirement began on March 31, 1999 and reports are required every two years thereafter. Energy Northwest submitted its most recent report to the NRC in March 2005.

Energy Northwest's current estimate of Columbia's decommissioning costs is $632.1 million (in 2005 dollars). This estimate, which is updated biannually, is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

Site restoration requirements for Columbia are governed by the site certification agreements between

Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC). Energy Northwest submitted a site restoration plan for Columbia that was approved by the EFSEC on June 12, 1995. Energy Northwest's current estimate of Columbia's site restoration costs is $79.6 million in constant dollars (based on 2005 Study) and is updated biannually along with the decommissioning estimate.

Both decommissioning and site restoration estimates (based on 2005 Study) are used as the basis for establishing a funding plan that includes escalation and interest earnings until decommissioning activities occur. Payments to the decommissioning and site restoration funds have been made since January 1985. The fair value of cash and investment securities in the decommissioning and site restoration funds as of June 30, 2005 totaled approximately $92.0 million and $11.0 million, respectively. Since September 1996 these amounts have been held and managed by BPA in external trust funds in accordance with NRC requirements and site certification agreements.

Materials and Supplies

Materials and supplies are valued at cost, using a weighted-average cost method.

Financing Expense, Bond Discount and Deferred Gain and Losses

Financing expenses and bond discounts are amortized over the terms of the respective bond issues using the bonds outstanding method.

In accordance with the Statement of Governmental Accounting Standard No. 23, losses on debt refundings have been deferred and amortized as a component of interest expense over the shorter of the remaining life of the old or new debt. The balance sheet includes the original deferred amount less recognized amortization expense and is included as a reduction to the new debt.

Current Maturities of Revenue Bonds

Current maturities (less than one year) of revenue bonds payable from restricted assets are reflected as current maturities. Debt that matures greater than one year is reflected as Long-Term Debt.

Accounts Payable and Accrued Expenses

Liabilities-Payable From Restricted Assets-Columbia includes $96.9 million for decommissioning and site restoration. Nuclear Project No. 1 includes $13.3 million for decommissioning and site restoration. The Nine Canyon Wind Project includes $0.5 million for decommissioning and site restoration.

Current Liabilities-Internal Service Fund accounts payable and accrued expenses include $4.0 million for payroll and related benefits, $17.2 million for compensated absences, and $2.4 million for outstanding warrants.

Other Non-Current Liabilities-Includes deferrals to cask liability and uranium enrichment assessment. Cask liability relates to the storage and disposal of spent fuel. Uranium enrichment assessment is related to fuel and is scheduled to be completed in two years.

Fair Value of Financial Instruments

The fair value of financial instruments has been estimated using available market information and certain assumptions. Considerable judgment is required in interpreting market data to develop fair value estimates and such estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The following methods and assumptions were used to estimate the fair value of each of the following financial instruments.

Financial instruments for which the carrying value is considered a reasonable approximation of fair value include: cash, accounts and other receivables, accounts payable and accrued expenses, advances from Members and others, other non-current liabilities and due to/from Participants, funds, and other Business Units. The fair values of investments (see Note C) and revenue bonds payable (see Outstanding Long-Term Debt Schedule) have been estimated based on quoted market prices for such instruments or based on the fair value of financial instruments of a similar nature and degree of risk.

Revenues

Energy Northwest accounts for expenses on an accrual basis, and recovers, through various agreements, actual cash requirements for operations and debt service for Columbia, Packwood, Nuclear Project No. 1 and Nuclear Project No. 3. For these Business Units, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no equity is accumulated. The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (liability) or as costs in excess of billings (asset), as appropriate. Such amounts will be settled during future operating periods.

Energy Northwest accounts for revenues and expenses on an accrual basis for the remaining Business Units. The difference between cumulative revenues and cumulative expenses is recognized as net revenue or losses and included in fund equity for each period.

Energy Northwest has accrued as income (contribution) from the DOE, Renewable Energy Performance Incentive (REPI) payments that enable the Nine Canyon Wind Project to receive funds based on generation as it applies to the REPI bill. The REPI was created as part of the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. For the first time in the history of the program, congressional funding for qualified wind programs was not fully funded. The Nine Canyon Wind Project recorded a receivable for sixty-eight (68%) of the applied REPI funding in the amount of $2.3 million for FY 2005, representing its share of funded amounts. The payment stream and the REPI receipts were projected to cover the total costs over the purchase agreement. Permanent shortfalls in REPI funding will lead to future increases in the billing of the Project participants in order to cover total Project costs.

Concentration of Credit Risk

Financial instruments which potentially subject Energy Northwest to concentrations of credit risk consist of available-for-sale investments, accounts receivable, other receivables, long-term receivables and costs in excess of billings. Energy Northwest invests exclusively in U.S. Government securities and agencies. Energy Northwest's accounts receivable and costs in excess of billings are concentrated with Project Participants and BPA through the net billing agreements. See Note E, Long-Term Debt, Security-Nuclear Projects Nos. 1, 3, Columbia and Packwood Lake Hydroelectric Project. The long-term receivable is with a large and stable company which Energy Northwest considers to be of low credit risk. Other large receivables are secured through the use of letters of credit and other similar security mechanisms or are with large and stable companies which Energy Northwest considers to be of low credit risk. As a consequence, Energy Northwest considers the exposure of the Business Units to concentration of credit risk to be limited.

Statements of Cash Flows

For purposes of the statements of cash flows, cash includes unrestricted and restricted cash balances. Short-term, highly liquid investments are not considered cash equivalents but are classified as available for sale investments.

NOTE C - CASH AND INVESTMENTS

Cash and investments for each Business Unit are separately maintained. Energy Northwest's deposits are insured by federal depository insurance or through the Washington Public Deposit Protection Commission. Energy Northwest resolutions and investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association and Federal Home Loan Banks. Safekeeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest Business Units.

Investments are classified as available-for-sale and are stated at fair value with unrealized gains and losses reported in investment income. Available-for-sale investments at June 30, 2005 are categorized below to give an indication of the types and amounts as well as maturities of investments held by each Business Unit at year-end. (See tables below)

Available-For-Sale Investments (Dollars in Thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
Columbia				
U.S. Government Agencies	$ 105,144	-	$ (10)	$ 105,134
Total	$ 105,144	-	$ (10)	$ 105,134
Packwood				
U.S. Government Treasury Bills	$ 2,719	-	-	$ 2,719
Total	$ 2,719	-	-	$ 2,719
Nuclear Project No. 1				
U.S. Government Agencies	$ 26,778	-	$ (3)	$ 26,775
Total	$ 26,778	-	$ (3)	$ 26,775
Nuclear Project No. 3				
U.S. Government Agencies	$ 26,843	-	$ (3)	$ 26,840
Total	$ 26,843	-	$ (3)	$ 26,840
Business Development Fund				
U.S. Government Agencies	$ 305	-	-	$ 305
Total	$ 305	-	-	$ 305
Grays Harbor				
U.S. Government Agencies	-	-	-	-
Total	-	-	-	-
Internal Service Fund				
U.S. Government Agencies	$ 28,849	-	$ (6)	$ 28,843
Total	$ 28,849	-	$ (6)	$ 28,843
Nine Canyon Wind				
U.S. Government Agencies	$ 8,101	-	$ (1)	$ 8,100
Total	$ 8,101	-	$ (1)	$ 8,100

Available-For-Sale Investments *(continued)*

	< 1 year	1-5 years	5-10 years	> 10 years	Total
Columbia					
U.S. Government Agencies	$ 105,134	-	-	-	$ 105,134
Total	$ 105,134	-	-	-	$ 105,134
Packwood					
U.S. Government Treasury Bills	$ 2,719	-	-	-	$ 2,719
Total	$ 2,719	-	-	-	$ 2,719
Nuclear Project No. 1					
U.S. Government Agencies	$ 26,775	-	-	-	$ 26,775
Total	$ 26,775	-	-	-	$ 26,775
Nuclear Project No. 3					
U.S. Government Agencies	$ 26,840	-	-	-	$ 26,840
Total	$ 26,840	-	-	-	$ 26,840
Business Development Fund					
U.S. Government Agencies	$ 305	-	-	-	$ 305
Total	$ 305	-	-	-	$ 305
Grays Harbor					
U.S. Government Agencies	$ -	-	-	-	$ -
Total	$ -	-	-	-	$ -
Internal Service Fund					
U.S. Government Agencies	$ 28,843	-	-	-	$ 28,843
Total	$ 28,843	-	-	-	$ 28,843
Nine Canyon Wind					
U.S. Government Agencies	$ 8,100	-	-	-	$ 8,100
Total	$ 8,100	-	-	-	$ 8,100

NOTE D - RETIREMENT BENEFITS

Substantially all Energy Northwest full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing multiple-employer public employee defined benefit and defined contribution retirement plans. The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to: Department of Retirements Systems, Administrative Services Division, P.O. Box 48380, Olympia, WA 98504-8380. The following disclosures are made pursuant to GASB Statement No. 27, "Accounting for Pensions by State and Local Government Employers."

Public Employee's Retirement System (PERS) Plans 1, 2, and 3 Plan Description

PERS is a cost-sharing, multiple-employer defined benefit pension plan. Membership in the plan includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts (other than judges in a judicial retirement system); employees of legislative committees; college and university employees not in national higher education retirement programs; judges of district and municipal courts; non-certificated employees of school districts; and employees of local government, including Energy Northwest. The PERS system includes three plans. Participants who joined the system by September 30, 1977 are Plan 1 members. Those joining thereafter are enrolled in Plan 2, unless they exercise an option to transfer their membership to Plan 3. PERS participants joining the system on or after March 1, 2002 for state and higher education employees, or September 1, 2002 for local government employees have the option of choosing membership in either PERS Plan 2 or PERS Plan 3. The option must be exercised within 90 days of employment. Retirement benefits are financed from employee and employer contributions and investment earnings. Retirement benefits in Plan 1 and Plan 2 are vested after completion of five years of eligible service. PERS Plan 3 participants are vested immediately.

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates, Plan 2 employer and employee rates, and Plan 3 employer contribution rates. Employee contribution rates for Plan 1 are established by statute at six percent and do not vary from year to year. The employer and employee contribution rates for Plan 2 and employer rate for Plan 3 are set by the director of the Department of Retirement Systems based on recommendations by the Office of the State Actuary to continue to fully fund the plan. All employers are required to contribute at the level established by state law. The methods used to determine the contribution requirements are established under state statute in accordance with chapters 41.40 and 41.45 Revised Code of Washington.

The required contribution rates for the defined benefit plan expressed as a percentage of current year covered payroll, as of June 30, 2005 were:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
Employer*	1.40%	1.40%	1.40%**
Employee	6.00%	1.18%	***

*The employer rates include the employer administrative expense fee currently set at 0.19%. This rate reflects the change effective September 1, 2004. Previous to this period the rate was 0.22%.

**Plan 3 defined benefits portion only.

***Variable from 5.0% minimum to 15.0% maximum based on rate selected by PERS 3 member.

Both Energy Northwest and the employees made the required contributions. Energy Northwest's required contributions for the years ended June 30 was:

	PERS Plan 1	PERS Plan 2	PERS Plan 3
2005	$86,067	$958,601	$364,653
2004	$101,132	$905,073	$336,973
2003	$108,239	$1,077,106	$ 95,821

In addition to the pension benefits available through PERS, Energy Northwest offers post-employment life insurance benefits to retirees who are eligible to receive pensions under PERS Plan 1, Plan 2, and Plan 3. Ninety-seven retirees have elected to participate in this insurance. In 1994, Energy Northwest's Executive Board approved provisions which continued the life insurance benefit to retirees at 25 percent of the premium for employees who retire prior to January 1, 1995 and charged the full 100 percent premium to employees who retired after December 31, 1994. The life insurance benefit is equal to the employee's annual rate of salary at retirement for non-bargaining employees retiring prior to January 1, 1995. The cost of coverage for employees who retired after January 1, 1995 is $2.33 per $1,000 of coverage with a maximum limit of $10,000. Employees who retired prior to January 1, 1995 contribute $.58 per $1,000 of coverage while Energy Northwest pays the remainder. Premiums are paid to the insurer on a current period basis.

At the time each employee retires, Energy Northwest accrues a liability for the actuarial value of estimated future premiums, net of retiree contributions. The total liability recorded at June 30, 2005 was $0.9 million for these benefits.

During FY 2005, pension costs for Energy Northwest employees and post-employment life insurance benefit costs for retirees were calculated and allocated to each Business Unit based on direct labor dollars. Approximately 93 percent of all such costs were allocated to Columbia during FY 2005.

401(k) and 457 Plan Deferred Compensation Plan

Energy Northwest provides a 401(k) Deferred Compensation Plan (the 401(k) Plan), and a 457 Deferred Compensation Plan. Both Plans are defined contribution plans that were established to provide a means for investing savings by employees for retirement purposes. All permanent, full time employees are eligible to enroll in the Plans. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations. For the 401(k) Plan, Energy Northwest matches 50% of the portion of the participant's salary deferral amount, which does not exceed 5% of the participant's 401(k) eligible earnings for the 401(k) Plan year. Participants direct the investment of their contributions. Participants are immediately vested in their contributions plus actual earnings thereon. During FY 2005 Energy Northwest contributed $2.1 million in employer matching funds.

NOTE E - LONG-TERM DEBT

Each Energy Northwest Business Unit is financed separately. The resolutions of Energy Northwest authorizing issuance of revenue bonds for each Business Unit provide that such bonds are payable from the revenues of that Business Unit. All bonds issued under Resolutions Nos. 769, 775 and 640 for Nuclear Projects Nos. 1, 3 and Columbia, respectively, have the same priority of payment within the Business Unit (the "Prior Lien Bonds"). All bonds issued under Resolutions Nos. 835, 838 and 1042 (the "Electric Revenue Bonds") for Nuclear Projects Nos. 1, 3 and Columbia, respectively, are subordinate to the Prior Lien Bonds and have the same subordinated priority of payment within the Business Unit.

During the year ended June 30, 2005, Energy Northwest issued, for Nuclear Projects 1, 3, and Columbia, the Series 2005-A Bonds, Series 2005-B Bonds and Series 2005-C Bonds. The Series 2005-A, 2005-B, and 2005-C Bonds, issued for Nuclear Project No. 1, Nuclear Project No. 3, and Columbia are fixed rate bonds with a weighted average coupon interest rate of 5.00%. The Series 2005-A Bond Proceeds of $346.6 million refunded $346.8 million, par amount, of outstanding bonds having a weighted average coupon interest rate of 5.88%. The $346.6 million of proceeds associated with the Series 2005-A Bonds were allocated to Nuclear Project No. 1 ($79.4 million), Columbia ($125.2 million), and Nuclear Project No. 3 ($142.0 million). This transaction resulted in a net loss for accounting purposes of $1.4 million for Nuclear Project 1, a net loss of $1.0 million for Nuclear Project 3, and a net gain of $.2 million for Columbia. According to GASB Statement No. 7, "Advance Refundings Resulting in Defeasance of Debt", the amortization of the gains and losses on the refundings are calculated based on the shorter of the life of the new debt compared to the old debt.

The Series 2005-A bonds resulted in the recognition of a net accounting loss of $2.2 million for the year ended June 30, 2005. Energy Northwest increased its aggregate debt service by $121.0 million over the next 13 years due to extending the date of maturities; however an economic gain of $4.2 million was obtained.

The Series 2005-B Bonds, issued for Nuclear Project No.1, Nuclear Project No. 3 and Columbia, in the aggregate amount of $3.6 million, are taxable fixed-rate bonds with a weighted average coupon interest rate of 4.11%. The 2005-B Bond Proceeds were used for the purpose of paying costs relating to the issuance of the Series 2005-A and Series 2005-B Bonds as well as certain costs relating to the refunding of certain outstanding bonds. Lastly, some of the Series 2005-B Bond Proceeds will be used to finance a portion of the cost of certain capital improvements.

The Series 2005-C Bonds, issued for Columbia, in the amount of $91.9 million, are fixed-rate bonds with an average coupon interest rate of 4.60%. The Series 2005-C Bonds were issued to finance a portion of the cost of certain capital improvements at Columbia and to pay costs relating to nuclear fuel purchases.

During the year ended June 30, 2005, Energy Northwest issued, for Nine Canyon Wind Project, the Series 2005 Bonds. The Series 2005 Bonds, issued for Nine Canyon Wind Project are fixed-rate bonds with a weighted average coupon interest rate of 4.77%. The Series 2005 Bond Proceeds of $65.6 million refunded $59.4 million of outstanding bonds having a weighted average coupon interest rate of 5.77%. This transaction resulted in a net loss for accounting purposes of $7.2 million for Nine Canyon Wind Project. According to GASB Statement No. 7, "Advance Refundings Resulting in Defeasance of Debt", the amortization of the gains and losses on the refundings are calculated based on the shorter of the life of the new debt compared to the old debt.

The Series 2005 Bonds resulted in the recognition of an accounting loss of $7.2 million for the year ended June 30, 2005. Energy Northwest decreased its aggregate debt service payments by $3.7 million over the next 19 years and obtained an economic gain of $2.8 million.

In prior fiscal years, Energy Northwest also defeased certain revenue bonds by placing the net proceeds from the refunding bonds in irrevocable trusts to provide for all required future debt service payments on the refunded bonds until their dates of redemption. Accordingly, the trust account assets and liability for the defeased bonds are not included in the financial statements in accordance with GASB statements No. 7 and 23. Including the FY 2005 defeasements, $260.5 million, $151.5 million, $304.1 million, and $59.4 million of defeased bonds were not called or had not matured at June 30, 2005, for Nuclear Projects Nos. 1 and 3, Columbia, and Nine Canyon Wind Project respectively.

Outstanding revenue bonds for the various Business Units as of June 30, 2005, and future debt service requirements for these bonds are presented as supplementary information at the end of the Financial Section of this report.

Security - Nuclear Projects Nos. 1 and 3 and Columbia

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

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

Security - Packwood Lake Hydroelectric Project

Energy Northwest, Benton County PUD and Franklin County PUD have signed Power Sales agreements which became effective November 4, 2002 and ran through October 30, 2004. A one-year extension was negotiated for the period beginning November 1, 2004 and extending through October 30, 2005. A new contract effective October 1, 2005 and extending through September 30, 2008 has been signed. Benton and Franklin County PUD's agree to pay Energy Northwest in exchange for the total output of electric capacity and energy delivered from the Packwood Generation Project. The Packwood Participants are obligated to pay annual costs of the Project including debt service, whether or not the Project is operable, until the outstanding bonds are paid or provisions are made for bond retirement, in accordance with the requirements of the bond resolution. The Participants also share project revenue to the extent that the amounts exceed project costs.

NOTE F - COMMITMENTS AND CONTINGENCIES

Nuclear Project No. 1 Termination

Since the Nuclear Project No.1 termination, Energy Northwest has been planning for the demolition of Nuclear Project No. 1 and restoration of the site, recognizing the fact that there is no market for the sale of the Project in its entirety and to-date, no viable alternative use has been found. The final level of demolition and restoration will be in accordance with agreements discussed later in Note F under "Nuclear Projects Nos. 1 and 4 Site Restoration."

Nuclear Project No. 3 Termination

In June 1994, the Nuclear Project No. 3 Owners Committee voted unanimously to terminate the Project. During 1995, a group from Grays Harbor County, Washington, formed the Satsop Redevelopment Project (SRP). The Satsop Redevelopment Project introduced legislation with the State of Washington under Senate Bill No. 6427, which passed and was signed by the Governor of the State of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 and Nuclear Project No. 5 exist for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights. In February 1999, Energy Northwest entered into a transfer agreement with the Satsop Redevelopment Project (SRP) to transfer the real and personal property at the site of Nuclear Project No. 3 and Nuclear Project No. 5. The SRP also agreed to assume regulatory responsibility for site restoration. Therefore, Energy Northwest is no longer responsible to the State of Washington and EFSEC for any site restoration costs.

Nuclear Projects Nos. 1 and 4 Site Restoration

Site restoration requirements for Nuclear Projects Nos. 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 the DOE. Energy Northwest submitted a site restoration plan for Nuclear Projects Nos. 1 and 4 to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment, or other techniques such that the sites pose minimal hazard to the public. EFSEC approved Energy Northwest's site restoration plan on June 12, 1995. In its approval, EFSEC recognized that there is uncertainty associated with Energy Northwest's proposed plan. Accordingly, EFSEC's conditional approval provides for additional reviews once the details of the plan are finalized. A new plan with additional details was submitted in FY 2003. This submittal was used to calculate the ARO discussed in Note G of the financial statements.

Business Development Fund Interest in Northwest Open Access Network

The Business Development Fund is a member of the Northwest Open Access Network ("NoaNet"). Members formed NoaNet pursuant to an Interlocal Cooperation Agreement for the development and efficient use of a communication network in conjunction with BPA for use by the Members and others.

The Business Development Fund has a 7.38% interest in NoaNet with an additional 25 percent step-up possible for a maximum 9.23 percent. As of June 30, 2005, NoaNet has $24.6 million in outstanding bonds. The members are obligated to pay the principal and interest on the bonds when due in the event and to the extent that

NoaNet's Gross Revenue (after payment of costs of Maintenance and Operation) is insufficient for this purpose. The maximum principal share (with step-up) that the Business Development Fund could be required to pay is $2.3 million. It is important to note that the Business Development Fund is not obligated to reimburse losses of NoaNet unless an assessment is made to NoaNet's members based on a two-thirds vote of the membership. In FY 2005 the Business Development Fund contributed $136K to NoaNet based on an assessment by the NoaNet members. This equity contribution was reduced to zero at year-end because NoaNet had a negative net equity position of $15.3 million. Future equity contributions, if any, will be treated the same until NoaNet has a positive equity position.

Business Development Fund Enriched Uranium Lease

In January 2004, the Business Development Fund entered into an enriched uranium lease agreement with two third parties whereby one third party leases enriched uranium to the Business Development Fund and concurrently allows the Business Development Fund to lease the enriched uranium to the other third party. The Business Development Fund earns a net margin of 0.625% per annum (through June 30, 2006) on the market value of the leased enriched uranium. The lease revenues and expenses are presented on a net basis in the Statements of Operations as the Business Development Fund does not take title to the enriched uranium, does not have inventory risk and is only at risk for the net margin. For FY 2005 the Business Development Fund recorded net revenues of $0.1 million in operating revenues under this agreement.

Other Litigation and Commitments

Energy Northwest is involved in various claims, legal actions and contractual commitments and in certain claims and contracts arising in the normal course of business. Although some suits, claims and commitments are significant in amount, final disposition is not determinable. In the opinion of management, the outcome of such litigation, claims or commitments will not have a material adverse effect on the financial positions of the Business Units or Energy Northwest as a whole. The future annual cost of the Business Units, however, may either be increased or decreased as a result of the outcome of these matters.

Nuclear Licensing and Insurance

Energy Northwest is a licensee of the Nuclear Regulatory Commission and is subject to routine licensing and user fees, to retrospective premiums for nuclear liability insurance, and to license modification, suspension, or revocation or civil penalties in the event of violations of various regulatory and license requirements.

The Price Anderson Act currently provides for nuclear liability insurance of over $10.7 billion per incident, which is covered by a combination of commercial nuclear insurance and mandatory industry self-insurance. Energy Northwest has purchased the maximum commercial insurance available of $300 million, which is the first layer of protection. The second layer of protection is provided through a mandatory industry self-insurance plan wherein each licensed nuclear facility required to participate in the plan (currently 104 participants) may be assessed up to $100.6 million per incident, subject to a maximum annual assessment of $10 million per year.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by Energy Northwest and BPA. The total amount of insurance purchased is currently $2.75 billion. The deductible for this coverage is $5.0 million per occurrence.

NOTE G - ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

Energy Northwest adopted SFAS 143 on July 1, 2002 (see Note B, Summary of Significant Accounting Policies). This Statement requires an entity to recognize the fair value of a liability for an ARO, measured at estimated fair value, for legal obligations related to the dismantlement and restoration costs associated with the retirement of tangible long-lived assets, such as nuclear decommissioning and site restoration liabilities, in the period in which it is incurred. Upon initial recognition of the AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted-risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Capitalized asset retirement costs are depreciated over the life of the related asset with accretion of the ARO liability classified as an operating expense on the statement of operations and fund equity each period. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss if the actual costs differ from the recorded amount. However, with regard to the net billed Projects, BPA is obligated to provide for the entire cost of decommissioning and site restoration, therefore, any gain or loss recognized upon settlement of the ARO results in an adjustment to either the billings in excess of costs (liability) or costs in excess of billings (asset), as appropriate, as no net revenue or loss is recognized, and no equity is accumulated for the net billed projects.

Energy Northwest has identified legal obligations to retire generating plant assets at the following business units: Columbia Generating Station, Nuclear Project No. 1 and Nine Canyon Wind Project. Decommissioning and site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the NRC regulations and site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the EFSEC and a lease agreement with the DOE (see Notes B and F). Prior obligations recorded with regard to the decommissioning obligation of Columbia and Nuclear Project No. 1 were reversed as of the adoption date, with revised obligations being recorded in accordance with SFAS No. 143. As a result of the net billing arrangement, the adoption of SFAS No. 143 for Columbia Generating Station and Nuclear Project No. 1 did not result in a cumulative effect adjustment on the statement of operations and fund equity, but resulted in a charge to costs in excess of billings.

Energy Northwest applied SFAS 143 to the ISFSI project, which is part of CGS, beginning in FY 2005 resulting in decommissioning and accretion expenses of $0.2 million and recognition of $1.4 million as the ARO.

An adjustment was made in FY 2005 for Nuclear Project No. 1 to account for costs incurred for decommissioning and site restoration. Costs incurred in FY 2005 of $6.2 million combined with a downward revision in future cash flows resulted in a downward adjustment to the ARO of $13.9 million.

As of June 30, 2005, Columbia Generating Station has a net asset value of $21.5 million and an accumulated liability of $96.9 million (includes ISFSI). Nuclear Project No. 1 has an accumulated liability of $13.3 million with a net asset value of $0.

Under the current agreement, the Nine Canyon Wind Project has the obligation to remove the generation facilities upon expiration of the lease agreement if requested by the lessors. The Nine Canyon Wind Project recorded the related ARO in FY 2003. As of June 30, 2005, the Nine Canyon Wind Project has a net asset value of $0.4 million and an accumulated liability of $0.5 million.

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

The following table describes the changes to Energy Northwest's ARO liabilities for the year ended June 30, 2005:

(Millions of dollars)

Columbia Generating Station

Balance at June 30, 2004	$90.75
Current year accretion expense	4.75
ARO at June 30, 2005	$95.50

ISFSI

Balance at June 30, 2004	$0.00
Asset Retirement Obligation incurred	1.36
Current year accretion expense	0.07
ARO at June 30, 2005	$1.43

Nuclear Project No. 1

Balance at June 30, 2004	$26.17
Less: Restoration costs incurred	(6.22)
Current year accretion expense	1.04
Revision in future restoration estimates	(7.68)
ARO at June 30, 2005	$13.31

Nine Canyon Wind Project

Balance at June 30, 2004	$0.50
Current year accretion expense	0.03
ARO at June 30, 2005	$0.53

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL

Preston|Gates|Ellis LLP

Energy Northwest

Goldman, Sachs & Co.

Citigroup Global Markets Inc.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Seattle-Northwest Securities Corporation

UBS Securities LLC

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$347,935,000/$438,630,000/$55,285,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue Refunding Bonds, Series 2006-A and Series 2006-B (Taxable) (the "2006 Bonds"). The 2006 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997/November 23, 1993], as amended by a resolution adopted on March 21, 2001, and (iii) a Supplemental Resolution adopted by the Executive Board on March 23, 2006 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

The Series 2006-A Bonds are subject to redemption in the manner and upon the terms and conditions set forth in the Bond Resolutions. The Series 2006-B Bonds are not subject to redemption prior to their stated maturity. The 2006 Bonds rank junior as to security and payment to bonds issued and outstanding under the Prior Lien Resolution. The 2006 Bonds rank equally as to security and payment with all other Parity Debt.

In connection with the issuance of the 2006 Bonds, we have examined a certified transcript of all of the proceedings taken in the matter of the issuance of the 2006 Bonds. 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. Energy Northwest is a municipal corporation and joint operating agency, duly created and existing under the laws of the State, including particularly the Act, having the right and power under the Act to acquire, construct, own and operate the Project, adopt the Bond Resolutions, issue the 2006 Bonds and apply the proceeds of the 2006 Bonds in accordance with the Supplemental Resolution.

2. The Bond Resolutions have been duly and lawfully adopted by Energy Northwest, are in full force and effect, are valid and binding upon Energy Northwest and are enforceable in accordance with their terms. Energy Northwest's covenants in the Prior Lien Resolution to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the Prior Lien Bonds prior to paying the principal of and interest on the 2006 Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2006 Bonds have been duly and validly authorized and issued under the Act and the Bond Resolutions and constitute valid and binding special revenue obligations of Energy Northwest, enforceable in accordance with their terms and the terms of the Bond Resolutions. The 2006 Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2006 Bonds are not a debt of the State or any political subdivision thereof (other than Energy Northwest), and neither the State nor any other political subdivision of the State is liable thereon.

The opinions above are qualified to the extent that the enforcement of the rights and remedies of the owners of the 2006 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, and we express no opinion regarding the enforceability of provisions in the Bond Resolutions that provide for rights of indemnification.

This opinion is given as of the date hereof and we assume no obligation to update, revise or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

Very truly yours,

PRESTON GATES & ELLIS LLP

By
Nancy M. Neraas

PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL

Preston|Gates|Ellis LLP

Energy Northwest

Goldman, Sachs & Co.

Citigroup Capital Markets

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Seattle-Northwest Securities Corporation

UBS Securities LLC

Ladies and Gentlemen:

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$347,935,000/$438,630,000/$55,285,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue Refunding Bonds, Series 2006-A and Series 2006-B (Taxable) (the "2006 Bonds"). The 2006 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [838/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997/November 23, 1993], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 23, 2006 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

In connection with the issuance of the 2006 Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/2/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/2/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement"), (collectively the "Agreements") by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

For the purpose of rendering this opinion, we have reviewed the following:

(a) The Constitution of the State and such statutes and regulations as we deemed relevant to this opinion, including particularly the Act;

(b) The Constitution of the United States of America and such statutes and regulations as we deemed relevant to this opinion, including particularly the Bonneville Project Act of 1937, as amended (the "Bonneville Act"), the Flood Control Act of 1944, Public Law 88-552, as amended, the Federal Columbia River Transmission System Act of 1974, as amended, and the Pacific Northwest Electric Power Planning and Conservation Act of 1980, as amended;

(c) Certified copies of the Electric Revenue Bond Resolution and the Supplemental Resolution;

(d) Certified copies of the Net Billing Agreements and the Assignment Agreement;

(e) The Certificate of the Chairman or Vice Chairman of the Executive Board, dated the date hereof, certifying that (i) neither Energy Northwest nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) The Certificate of the Administrator, dated the date hereof, certifying that (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement, or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement, and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(g) Certified copies of the proceedings of Energy Northwest authorizing the execution and delivery of the Net Billing Agreements and the Assignment Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, *inter alia*, (i) the office of Administrator was duly established and is validly existing under the Bonneville Act, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the Assignment Agreement, and (iii) each of the Net Billing Agreements and the Assignment Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System*, *et al*., 752 F.2d 1423 (9th Cir. 1985), *cert. denied*, 474 U.S. 1055 (1986)) ("Springfield");

(j) A certified copy of Energy Northwest Resolution No. [769/640/775] as amended and supplemented (the "Prior Lien Resolution"); and

(k) Such other documents, agreements, proceedings, pleadings, court decisions, statutes, matters and questions of law as we deemed necessary or appropriate for the purposes hereof.

Based upon the foregoing and in reliance thereon and based on the assumptions, exceptions and conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Projects 1 and 3 consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville Power Administration and the Participants currently obligated under the Net Billing Agreements, enforceable against such parties in accordance with its terms.

The foregoing opinion is subject to the following limitations, qualifications, exceptions, and assumptions:

(A) In rendering the opinion as to the enforceability of the Net Billing Agreements as to the Participants, we have assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations as therein stated, under the Net Billing Agreements and Assignment Agreement. The assumption in the prior sentence does not limit or affect our opinion as to the enforceability of the Net Billing Agreements and Assignment Agreement against Bonneville.

(B) The enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

(C) In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the Chairman or Vice Chairman of the Executive Board and the Administrator referred to above in paragraphs (e) and (f); and (3) (A) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (B) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreement to which such Participant is a party and that all assignments of any Participant's obligations under the Net Billing Agreements were properly done, and (C) with respect to the Participant's obligations under the Net Billing Agreements, no violation of or conflict with the provisions of applicable law, and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

(D) The opinions expressed herein are qualified to the extent that the characterization of, and the enforceability of any rights or remedies in the Agreements, may be limited by concepts of materiality, reasonableness, good faith and fair dealing, and rules governing specific performance, injunctive relief, marshalling, subrogation and other equitable remedies, regardless of whether raised in a court of law or otherwise**.** The opinions expressed herein are based on an analysis of existing laws (including, but not limited to, the law that provides that Bonneville may make expenditures from the Bonneville Fund which have been included in Bonneville's budget submitted to Congress without further appropriation or fiscal year limitation), regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof.

(E) We express no opinion with respect to any provision for a remedy which is determined to be in the nature of a penalty, forfeiture or punitive damages, or which would provide the claimant with a duplication of damage awards or cumulative remedy, or which waives the applicability of any rule requiring an election of remedies. We express no opinion with respect to the obligation of Bonneville or any Participant to pay any debt or other obligation related to the Project on an accelerated basis.

(F) Our opinions are subject to the context rule of interpretation of contracts, which provides that even though terms of a contract may be unambiguous, courts may admit extrinsic evidence to interpret the contract.

This letter has been prepared solely for your use in connection with the transactions contemplated by the Agreements and should not be quoted in whole or in part or otherwise be referred to nor be relied upon by, filed with or furnished to, any governmental agency or other person or entity (other than your legal and professional advisors) without the prior consent of this firm. No attorney-client relationship has existed or exists between our firm and Bonneville, the Participants or the Underwriters with respect to the subject matter hereof or by virtue of this opinion. This letter opinion speaks as of its date and we do not hereby undertake to update this letter opinion. The opinions expressed in this letter are limited to the matters set forth in this letter, and no other opinions should be inferred beyond the matters expressly stated.

Very truly yours,

PRESTON GATES & ELLIS LLP

By
Nancy M. Neraas

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PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL

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

Energy Northwest
$338,775,000 Project 1 Energy Northwest Revenue Refunding Bonds, Series 2006-A
$434,210,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-A
$54,760,000 Project 3 Energy Northwest Revenue Refunding Bonds, Series 2006-A
$9,160,000 Project 1 Energy Northwest Revenue Refunding Bonds, Series 2006-B (Taxable)
$4,420,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-B (Taxable)
$525,000 Project 3 Energy Northwest Revenue Refunding Bonds, Series 2006-B (Taxable)

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $338,775,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2006-A (the "Project 1 2006-A Bonds"), $434,210,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-A (the "Columbia 2006-A Bonds"), $54,760,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2006-A (the "Project 3 2006-A Bonds," and together with the Project 1 2006-A Bonds and the Columbia 2006-A Bonds, the "Series 2006-A Bonds"), $9,160,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Project 1 2006-B Taxable Bonds"), $4,420,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Columbia 2006-B Taxable Bonds") and $525,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2006-B (Taxable) (the "Project 3 2006-B Taxable Bonds," and together with the Project 1 2006-B Taxable Bonds and the Columbia 2006-B Taxable Bonds, the "Series 2006-B Taxable Bonds"). The Project 1 2006-A Bonds and the Project 1 2006-B Taxable Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), and Resolution No. 835, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 23, 2006 (the "Project 1 Resolution"). The Columbia 2006-A Bonds and the Columbia 2006-B Taxable Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted by Energy Northwest on October 23, 1997, as amended and supplemented, and supplemental resolutions adopted on March 23, 2006 (the "Columbia Resolution"). The Project 3 2006-A Bonds and the Project 3 2006-B Taxable Bonds are being issued pursuant to the Act and Resolution No. 838, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 23, 2006 (the "Project 3 Resolution," and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Series 2006-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest. The Series 2006-B Taxable Bonds are being issued for the purpose of paying certain costs of issuance and other refunding costs relating to the Series 2006-A Bonds and the Series 2006-B Taxable Bonds.

In such connection, we have reviewed certified copies of the Resolutions, the Tax Matters Certificate executed and delivered by Energy Northwest on the date hereof and the Tax Matters Certificate executed and delivered on the date hereof by the Bonneville Power Administration (collectively, the "Tax Certificates"); the opinion of Preston Gates & Ellis LLP, as Bond Counsel; additional certificates of Energy Northwest, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

Certain agreements, requirements and procedures contained or referred to in the Resolutions, the Tax Certificates and other relevant documents may be changed and certain actions (including, without limitation, defeasance of Series 2006-A Bonds) may be taken or omitted under the circumstances and subject to the terms and conditions set forth in such documents. No opinion is expressed herein as to any Series 2006-A Bond or the interest thereon if any such change occurs or action is taken or omitted upon the advice of counsel other than ourselves.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Our engagement with respect to the Series 2006-A Bonds and Series 2006-B Taxable Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the second paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolutions and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Series 2006-A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights under the Series 2006-A Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to the bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate case and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated March 23, 2006 relating to the Series 2006-A Bonds and the 2006-B Taxable Bonds, or other offering material relating to those Bonds and express no opinion with respect thereto.

We have relied with your consent on the opinion of Preston Gates & Ellis LLP, Bond Counsel, with respect to the validity of the Series 2006-A Bonds and the Series 2006-B Taxable Bonds and with respect to the due authorization and issuance of the Series 2006-A Bonds and Series 2006-B Taxable Bonds.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the opinion that interest on the Series 2006-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). We also are of the opinion that interest on the Series 2006-B Taxable Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code or Section 103 of the Internal Revenue Code of 1986. Interest on the Series 2006-A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

Except as expressly stated herein, we express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Series 2006-A Bonds and the Series 2006-B Taxable Bonds.

Series 2006-B Taxable Bonds Circular 230 Disclaimer:

Investors are urged to obtain independent tax advice regarding the Series 2006-B Taxable Bonds based upon their particular circumstances. The tax discussion above regarding the Series 2006-B Taxable Bonds was not intended or written to be used, and cannot be used, for the purposes of avoiding taxpayer penalties. The advice was written to support the promotion or marketing of the Series 2006-B Taxable Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2006 BUDGETS

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Albion, Idaho	0.004	0.016	0.003
	Alder Mutual Light Company, Washington	0.002		
	City of Bandon, Oregon	0.166	0.263	0.144
*	Public Utility District No. 1 of Benton County, Washington	4.965	5.350	4.295
	Benton Rural Electric Association, Washington	0.308	0.666	0.645
	Big Bend Electric Cooperative, Inc., Washington	0.179	1.610	0.374
	Blachly-Lane County Cooperative Electric Association, Oregon	0.234	0.272	0.491
	Blaine City Light, Washington	0.109	0.185	0.101
	City of Bonners Ferry, Idaho, Electric Department	0.115	0.182	0.099
	City of Burley, Idaho, Electric	0.179	0.694	0.155
	Canby Utility Board, Oregon	0.296	0.090	0.256
	City of Cascade Locks, Oregon	0.074	0.054	0.064
	Central Electric Cooperative, Inc., Oregon	0.462	0.586	0.966
	Central Lincoln People's Utility District, Oregon	4.169	4.017	3.607
	City of Centralia, Washington, Electric Light Department	0.298	0.739	0.258
*	Public Utility District No. 1 of Chelan County, Washington	0.501		0.433
	City of Cheney, Washington, Light Department	0.511	0.539	0.442
	Public Utility District No. 1 of Clallam County, Washington	1.157	1.769	1.001
	Public Utility District No. 1 of Clark County, Washington	14.305	6.151	13.633
	Clatskanie People's Utility District, Oregon	0.418	1.996	0.530
	Clearwater Power Company, Idaho	0.274	0.775	0.573
	Columbia Basin Electric Cooperative, Inc., Oregon	0.161	0.673	0.338
	Columbia Power Cooperative Association, Oregon	0.042	0.143	0.088
	Columbia Rural Electric Association, Inc., Washington	0.621	0.761	1.298
	Consolidated Irrigation District No. 19, Washington	0.005		0.005
	Consumers Power, Inc., Oregon	1.068	0.453	2.242
	Coos-Curry Electric Cooperative, Inc., Oregon	0.232	1.634	0.781
	Town of Coulee Dam, Washington, Light Department	0.048	0.137	0.041
	Public Utility District No. 1 of Cowlitz County, Washington	7.379	5.525	3.461
	City of Declo, Idaho	0.026	0.019	0.023
	Public Utility District No. 1 of Douglas County, Washington	0.044		0.049
	Douglas Electric Cooperative, Inc., Oregon	0.331	0.363	0.692
	City of Drain, Oregon, Light and Power	0.096	0.218	0.083
	East End Mutual Electric Company, Ltd., Idaho	0.011	0.033	0.023
	Town of Eatonville, Washington	0.010		
	City of Ellensburg, Washington	0.780	1.028	0.675
	Elmhurst Mutual Power and Light Co., Washington	0.170		
	Eugene Water & Electric Board, Oregon	0.061		
	Fall River Rural Electric Cooperative, Inc., Idaho	0.188	0.409	0.393
	Farmers Electric Co., Idaho	0.005	0.041	0.011
*	Public Utility District No. 1 of Ferry County, Washington	0.105	0.171	0.091
	City of Fircrest, Washington			
	Flathead Electric Cooperative, Inc., Montana	0.123	0.370	0.257

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Forest Grove, Oregon, Light and Power Department	0.470	0.181	0.091
*	Public Utility District No. 1 of Franklin County, Washington	1.330	2.370	1.151
	Glacier Electric Cooperative, Inc., Montana	0.098		
*	Public Utility District No. 2 of Grant County, Washington	0.486		0.420
*	Public Utility District No. 1 of Grays Harbor County, Washington	2.769	3.075	2.386
	Harney Electric Cooperative, Inc., Oregon	0.105	0.719	0.221
	City of Heyburn, Idaho	0.167	0.504	0.145
	Hood River Electric Cooperative, Oregon	0.224	0.502	0.469
	Idaho County Light and Power Cooperative Association, Inc., Idaho	0.047	0.186	0.098
	City of Idaho Falls, Idaho, Electric Division	0.908	2.376	0.787
	Inland Power & Light Company, Washington	0.907	1.222	1.915
*	Public Utility District No. 1 of Kittitas County, Washington	0.238	0.220	0.206
*	Public Utility District No. 1 of Klickitat County, Washington	0.517	1.009	0.448
	Kootenai Electric Cooperative, Inc., Idaho	0.212	0.391	0.443
	Lakeview Light and Power Company, Washington	0.168		
	Lane Electric Cooperative, Inc., Oregon	0.537	1.452	1.123
	Public Utility District No. 1 of Lewis County, Washington	1.276	2.274	1.103
	Lincoln Electric Cooperative, Inc., Montana	0.087	0.255	0.182
	Lost River Electric Cooperative, Inc., Idaho	0.056	0.202	0.118
	Lower Valley Power and Light, Inc., Wyoming	0.266	0.820	0.557
*	Public Utility District No. 1 of Mason County, Washington	0.186	0.231	0.161
*	Public Utility District No. 3 of Mason County, Washington	1.274	1.446	1.265
	Town of McCleary, Washington	0.069	0.234	0.059
	McMinnville Water and Light, Oregon	1.141	1.227	0.547
	Midstate Electric Cooperative, Inc., Oregon	0.336	0.488	0.704
	City of Milton, Washington	0.027		
	Milton-Freewater Light and Power, Oregon	0.238	0.583	0.002
	City of Minidoka, Idaho	0.001	0.005	0.001
	Missoula Electric Cooperative, Inc., Montana	0.168	0.294	0.352
	City of Monmouth, Oregon	0.679	0.236	0.588
	Nespelem Valley Electric Cooperative, Inc., Washington	0.059	0.149	0.123
	Northern Lights, Inc., Idaho	0.234	0.455	0.489
	Northern Wasco County People's Utility District, Oregon	0.246	0.051	0.213
	Ohop Mutual Light Company, Washington	0.025		
	Okanogan County Electric Cooperative, Inc., Washington	0.038	0.190	0.079
*	Public Utility District No. 1 of Okanogan County, Washington	0.255	1.042	0.143
	Orcas Power and Light Company, Washington	0.257	0.725	0.733
*	Public Utility District No. 2 of Pacific County, Washington	1.006	1.503	0.870
	Parkland Light and Water Company, Washington	0.096		
	Public Utility District No. 1 of Pend Oreille County, Washington	0.055		0.047
	Peninsula Light Company, Washington	0.261		
	City of Port Angeles, Washington	0.665	2.416	0.576
	Raft River Rural Electric Cooperative, Inc., Idaho	0.224	0.853	0.468
	Ravalli County Electric Cooperative, Inc., Montana	0.195	0.301	0.409
*	City of Richland, Washington, Energy Service Department	1.828	2.780	1.592
	Riverside Electric Company, Idaho	0.007	0.020	0.015
	City of Rupert, Idaho, Electric Department	0.123	0.348	0.106
	Salem Electric, Oregon	0.662	0.453	1.385

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	Salmon River Electric Cooperative, Inc., Idaho	0.046	0.170	0.097
	City of Seattle, Washington, City Light Department	8.605	7.193	7.206
*	Public Utility District No. 1 of Skamania County, Washington	0.321	0.547	0.278
*	Public Utility District No. 1 of Snohomish County, Washington	19.584	15.363	19.334
	South Side Electric Lines, Inc., Idaho	0.032	0.073	0.067
	City of Springfield, Oregon, Utility Board	0.228	0.363	0.238
	Town of Steilacoom, Washington	0.038		
	City of Sumas, Washington	0.021	0.048	0.018
	Surprise Valley Electrification Corp., California	0.049	0.323	0.102
*	Tacoma Power, Washington	5.971		5.803
	Tanner Electric Cooperative, Washington	0.050	0.122	0.104
	Tillamook People's Utility District, Oregon	0.963	1.729	0.833
	Umatilla Electric Cooperative, Oregon	0.997	0.036	2.107
	United Electric Cooperative, Inc., Idaho	0.320	0.466	0.670
	Vera Water and Power, Washington	0.323	0.701	0.401
	Vigilante Electric Cooperative, Inc., Montana	0.042	0.294	0.088
*	Public Utility District No. 1 of Wahkiakum County, Washington	0.229	0.328	0.198
	Wasco Electric Cooperative, Inc., Oregon	0.116	0.342	0.244
	Wells Rural Electric Company, Nevada	0.102		0.214
	West Oregon Electric Cooperative, Inc., Oregon	0.121	0.182	0.252
	Public Utility District No. 1 of Whatcom County, Washington	0.387		0.335
	TOTAL PARTICIPANT UTILITIES (112)	100.000	100.000	100.000

* Energy Northwest members.

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SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS

The following summary of certain provisions of the Net Billing Agreements, the Project No. 2 Project Agreement (hereinafter referred to as the "Columbia Project Agreement"), and the Assignment Agreements does not purport to be complete. A copy of the foregoing agreements may be obtained from Energy Northwest. The capitalization of any word or words which are not conventionally capitalized indicates that such words are defined in the Net Billing Agreements.

THE NET BILLING AGREEMENTS

On February 6, 1973, Energy Northwest, Bonneville and each Project 1 Participant entered into a Project 1 Net Billing Agreement. As originally executed, the Project 1 Net Billing Agreements contained a description of Project 1 which included the use of the generating facilities which are a part of HGP. Subsequently, on May 31, 1974, Energy Northwest, Bonneville and each Project 1 Participant entered into Amendatory Agreement No. 1 to each Project 1 Net Billing Agreement (the "Project 1 Amendatory Agreements"). Under the Project 1 Amendatory Agreements, among other things, the description of Project 1 was changed so that it no longer includes the use of HGP generating facilities. However, the provisions relating to the obligations incurred with respect to HGP after July 1, 1980 remain in effect. See "ENERGY NORTHWEST — HANFORD GENERATING PROJECT" in this Official Statement.

On January 4, 1971, Energy Northwest, Bonneville and each Columbia Participant entered into a Columbia Net Billing Agreement.

On September 25, 1973, Energy Northwest, Bonneville and each Project 3 Participant entered into a Project 3 Net Billing Agreement.

Many of the provisions of the Net Billing Agreements have been summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement. A summary of certain additional provisions of the Net Billing Agreements, as amended, follows. Except where the text indicates otherwise, reference to Project 1 Net Billing Agreements is to such Agreements as amended by the Project 1 Amendatory Agreements. The summary describes the common features of, and highlights the differences among, the Net Billing Agreements for each of Project 1, Columbia and Project 3. Each of the Net Billing Agreements for the same Net Billed Project is identical except as to the Participants' shares.

Term

Each Net Billing Agreement became effective upon its execution and delivery and will terminate as provided therein. See "Termination" below.

Although the Net Billing Agreements may be terminated prior to the maturity of the related Net Billed Bonds, the obligation of each of the Participants thereunder to pay its proportionate share of debt service on the related Net Billed Bonds shall continue until such Net Billed Bonds have been retired. Bonneville will continue to be obligated to offset or credit these payments against payments pursuant to the Participant's contracts with Bonneville.

Project 1 and Project 3 have been terminated, and portions of the Project 1 and Project 3 Net Billing Agreements have been terminated. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement.

Ownership and Operation

Energy Northwest covenants in the Columbia Net Billing Agreement to use its best efforts to arrange for the financing, design, construction, operation and maintenance of the Columbia Generating Station. Similar covenants of Energy Northwest under the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

Sale, Purchase and Assignment

Under the Columbia Net Billing Agreements, Energy Northwest sells, and each Participant purchases, the Participant's share of the Columbia Generating Station capability and each Participant in turn assigns its share of such capability to Bonneville. Such shares in the Columbia Generating Station for the fiscal year 2006 is shown in Appendix F in this Official Statement. Similar provisions in the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

The provisions of the Net Billing Agreements with respect to payments are summarized under the heading "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS" in this Official Statement.

If Bonneville is unable to satisfy its obligation to a Participant by net billing, assignment or cash payment and determines that this condition will continue for a significant period, the affected Participant may direct that all or a portion of the energy associated with its share of the Columbia Generating Station capability be delivered by Energy Northwest for the

Participant's account at a specified point of delivery, either for the expected period of such inability or the remainder of the term of the Columbia Net Billing Agreement, whichever is specified by the Participant when it elects to have such energy delivered to it. The amount of energy delivered will be limited to the amount of the Participant's share of the Columbia Generating Station capability for which payment by Bonneville cannot be made.

Energy Northwest Costs Payable Under Net Billing Agreements

All costs of Project 1, Columbia and Project 3 are payable under the respective Net Billing Agreements, and the Annual Budgets adopted by Energy Northwest shall make provision for all such costs, including accruals and amortizations, resulting from the ownership, operation (including cost of fuel), and maintenance of Project 1, Columbia and Project 3 and repairs, renewals, replacements, and additions to the Projects, including, but not limited to, the amounts which Energy Northwest is required under the respective Prior Lien Resolutions and Electric Revenue Bond Resolutions to pay into the various funds provided for in the resolutions for debt service and all other purposes. Each Participant is required to pay the amount specified in the Annual Budget, less amounts payable from sources other than payments under the Net Billing Agreements, multiplied by such Participant's share of Project capability.

Termination

If the Columbia Generating Station is ended pursuant to Section 15 of the Columbia Project Agreement, as described below under "THE PROJECT AGREEMENTS," Energy Northwest is required to give notice of termination of the Columbia Net Billing Agreement effective upon the date of termination of such Project Agreement. Energy Northwest will then terminate all activities relating to construction and operation of the Project and shall undertake the salvage and disposition or sale of such Project as provided in the Columbia Project Agreement.

In May 1994, the Board of Directors of Energy Northwest adopted a resolution which terminated Project 1 and a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. In June 1994, the Project 3 Owners Committee voted unanimously to terminate Project 3. In October 1998, Energy Northwest acquired all of the remaining assets of Project 3. Since that time, Energy Northwest has sold a portion of the Project 3 site to the Satsop Redevelopment Project and the balance of the site to Duke Energy Grays Harbor LLC. See "ENERGY NORTHWEST — PROJECT 1," "– PROJECT 3" and "– OTHER ACTIVITIES" and "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Post Termination Agreements."

For a description of payments required to be made following termination of the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures" in this Official Statement.

Modification and Assignment of Agreement

Each Net Billing Agreement provides that it shall not be amended, modified or otherwise changed by agreement of the parties thereto in any manner that will impair or adversely affect the security afforded by each Net Billing Agreement's provision for the payment of the principal, interest, and premium, if any, on the related Net Billed Bonds. The Net Billing Agreements further provide that, except for the reassignments of Participants' shares of Project capability provided for therein, no transfer or assignment of the Net Billing Agreements by any party thereto (except to the United States or an agency thereof) is permitted without the written consent of the other parties and that no assignment or transfer relieves the parties of any obligations thereunder.

Participants' Review Board

Each of the Net Billing Agreements for Columbia provides for the establishment of a Participants' Review Board consisting of nine members who are elected by the Participants in Columbia. Except in the event of an emergency requiring immediate action, copies of all bids, evaluations and proposed contracts and awards for amounts in excess of $500,000 shall be submitted to the Participant's Review Board. All Construction and Annual Budgets and fuel management plans, including amendments thereto, and plans for refinancing Columbia are required to be submitted by Energy Northwest to the Participants' Review Board within a reasonable time prior to the time such proposed budgets and plans are adopted by Energy Northwest.

The Net Billing Agreements provide that written recommendations of the Participants' Review Board shall be forwarded to Energy Northwest within a reasonable time and that Energy Northwest will consider such recommendations, giving due regard to Prudent Utility Practice and Energy Northwest's statutory duties. If Energy Northwest modifies or rejects a written recommendation of the Participants' Review Board, the Participants' Review Board may refer the matter to the Project Consultant in the manner described in the Project Agreement for his written decision and his decision shall be binding. Pending any such decision by the Project Consultant, Energy Northwest shall proceed in accordance with the Project Agreement. See "THE PROJECT AGREEMENTS — Term" hereinafter. The Net Billing Agreements provide that the provisions described above shall not affect the procedure for the settlement of any dispute between Bonneville and Energy Northwest under the Net Billing Agreements or the Project Agreement. See "THE PROJECT AGREEMENTS — Bonneville's Approval and Project Consultant" hereinafter in this Appendix G.

Prudent Utility Practice has the same meaning as is given in “THE PROJECT AGREEMENTS — Design Licensing and Construction of the Project.”

The Net Billing Agreements provide that, except as specifically provided in the Project Agreement, Energy Northwest shall not proceed with any item as proposed by it and not concurred in by Bonneville without approval of the Participants' Review Board.

THE PROJECT AGREEMENTS

On February 6, 1973, Energy Northwest and Bonneville entered into an agreement (the “Project 1 Project Agreement”) which, among other things, provided standards for the design, licensing, financing, construction, fueling, operation and maintenance of Project 1, and for the making of any replacements, repairs or capital additions thereto. On May 31, 1974, Energy Northwest and Bonneville entered into Amendatory Agreement No. 1 to the Project 1 Project Agreement for the purpose of changing the description of Project 1 to conform to the changes made in the Project 1 Net Billing Agreements and to revise provisions relating to HGP.

On January 4, 1971, Energy Northwest and Bonneville entered into an agreement (the “Columbia Project Agreement”) which, among other things, contains provisions with respect to the licensing, financing, construction, fueling, operation and maintenance of Columbia, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Columbia Net Billing Agreements.

On September 25, 1973, Energy Northwest and Bonneville entered into an agreement (the “Project 3 Project Agreement” and, together with the Project 1 Project Agreement and the Columbia Project Agreement, the “Project Agreements”) which, among other things, contained provisions with respect to the financing, construction, operation and maintenance of Project 3, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Project 3 Net Billing Agreements.

Term

The Project 1 Project Agreement terminated as provided in Section 15 of the Project 1 Project Agreement in May 1994 when the Board of Directors of Energy Northwest adopted a resolution terminating Project 1.

The Columbia Project Agreement became effective upon its execution and delivery and will terminate as follows:

Columbia shall terminate and Energy Northwest shall cause Columbia to be salvaged, discontinued, decommissioned and disposed of or sold, in whole or in part, to the highest bidder or bidders, or disposed of in such other manner as the parties may agree when:

(a) Energy Northwest determines that it is unable to construct, operate, or proceed as owner of Columbia due to licensing, financing, or operating conditions or other causes which are beyond its control,

(b) The parties determine that Columbia is not capable of producing energy consistent with Prudent Utility Practice, or, if the parties disagree, the Project Consultant so determines, or

(c) Bonneville directs the end of Columbia pursuant to the provisions of the Columbia Project Agreement, which provides that if the estimated cost of a replacement or repair or capital addition required by a governmental agency after the date of commercial operation exceeds 20% of the then depreciated value of Columbia, Bonneville may direct that Energy Northwest end Columbia in accordance with Section 15.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. The Project 3 Owners Committee voted unanimously to terminate Project 3 and the Project 3 Project Agreement terminated in June 1994.

Design, Licensing and Construction of the Project

In the Columbia Project Agreement, Energy Northwest agrees, among other things, (i) to perform its duties and exercise its rights under such agreement in accordance with Prudent Utility Practice; (ii) to use its best efforts to obtain all licenses, permits and other rights and regulatory approvals necessary for the ownership, construction, and operation of the related Project; (iii) to construct the related Project in accordance with Prudent Utility Practice; and (iv) to keep Bonneville informed of all significant matters with respect to planning and construction of the Project.

“Prudent Utility Practice,” as defined in the Columbia Project Agreement, at a particular time means any of the practices, methods and acts, including those engaged in or approved by a significant portion of the electrical utility industry prior to such time, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. In evaluating whether any matter conforms to Prudent Utility Practice, Bonneville, Energy Northwest and any Project Consultant shall take into account the fact that Energy Northwest is a municipal corporation with statutory duties and responsibilities and the objective to integrate the entire Project capability with the generating resources of the Federal System in order to achieve optimum utilization of the resources of that System taken as a whole and to achieve efficient and economical operation of that System.

Financing

With respect to Columbia, Energy Northwest agrees in the Columbia Project Agreement to use its best efforts to issue and sell Columbia Net Billed Bonds (if such Bonds may then be legally issued and sold) to finance the costs of Columbia and of any capital additions, renewals, repairs, replacements or modifications to Columbia.

The Columbia Project Agreement also provides that Energy Northwest may, after submitting its financing proposal to Bonneville, or shall, if requested by Bonneville, authorize the issuance and sale of additional Columbia Net Billed Bonds to refund outstanding Columbia Net Billed Bonds in accordance with the Columbia Net Billed Resolution. A proposal to refund outstanding Columbia Net Billed Bonds is required to be referred to the Project Consultant if, in the judgment of Bonneville or Energy Northwest, no substantial benefits will be achieved by such refunding. See "Bonneville's Approval and Project Consultant" below.

Net Billed Resolutions and resolutions of Energy Northwest supplementing or amending the Net Billed Resolutions are subject to approval by Bonneville, and Bonneville has approved each Net Billed Resolution and each supplemental resolution.

Budgets

Separate Annual Budgets for the Net Billed Projects will be prepared annually. See "SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS — Payment Procedures." The Annual Budget and any amendment thereof are to be submitted to Bonneville for its approval. In the absence of any objection by Bonneville, the Annual Budget will become effective within 30 days after submittal, and within seven days in the case of any amendment thereof. Any item disapproved is required to be referred to the Project Consultant. See "Bonneville's Approval and Project Consultant" below.

Operation and Maintenance

Energy Northwest shall operate and maintain Columbia in accordance with Prudent Utility Practice and in accordance with the requirements of government agencies having jurisdiction.

Bonds for Replacements, Repairs and Capital Additions

If in any contract year the amounts in an Annual Budget relating to renewals, repairs, replacements and betterments and for capital additions necessary to achieve design capability or required by governmental agencies ("Amounts for Extraordinary Costs"), whether or not such amounts are costs of operation or costs of construction, exceed the amount of reserves, if any, maintained for such purpose pursuant to the Columbia Net Billed Resolutions plus the proceeds of insurance, if any, available by reason of loss or damage to Columbia, by the lesser of (1) $3,000,000 or (2) an amount by which the amount of Bonneville's estimate of the total of the net billing credits available in such contract year to the Participants in Columbia and the amounts of such reserves and insurance proceeds, if any, exceeds the Annual Budget for such contract year exclusive of Amounts for Extraordinary Costs, Energy Northwest is required to, in good faith, use its best efforts to issue and sell Columbia Net Billed Bonds to pay such excess.

Bonneville's Approval and Project Consultant

If a proposal submitted by Energy Northwest to Bonneville under any provision of the Columbia Project Agreement is not disapproved by Bonneville within the time specified or, if no time is specified, within seven days after receipt, the proposal is deemed approved. With certain exceptions specified in the Columbia Project Agreement (including Bonneville's right to approve a Net Billed Resolution and any supplemental resolutions), disapproval by Bonneville is required to be based solely on whether the proposal is consistent with Prudent Utility Practice.

If any proposal subject to approval by Bonneville is disapproved by Bonneville and an alternative proposal is suggested by Bonneville, Energy Northwest shall adopt such suggestion or, within seven days after receipt of such disapproval, shall appoint a Project Consultant acceptable to Bonneville to review the proposal. Proposals found by the Project Consultant to be consistent with Prudent Utility Practice shall become immediately effective. Proposals found by the Project Consultant to be inconsistent with Prudent Utility Practice shall be modified to conform to the recommendation of the Project Consultant or as the parties otherwise agree and shall become effective as and when modified. If any proposal referred to the Project Consultant has not been resolved and will affect the continuous operation of Columbia, Energy Northwest shall continue to operate Columbia and may proceed as proposed by Energy Northwest, or as proposed by Bonneville, or as modified by mutual agreement of Energy Northwest and Bonneville. If Energy Northwest proceeds with its proposal, and it is determined by the Project Consultant to be inconsistent with Prudent Utility Practice, Energy Northwest shall bear any net increase in the cost of construction or operation of Columbia resulting from such proposal without charge to Columbia to the extent such proposal is found by the Project Consultant to be inconsistent with Prudent Utility Practice.

ASSIGNMENT AGREEMENTS

In 1984, Energy Northwest and Bonneville executed Assignment Agreements for each of Project 1, Columbia and Project 3. The purpose of the Assignment Agreements is to assure that Bonneville receives the entire output of Project 1, Columbia, and Project 3, and to assure that Energy Northwest receives sufficient funds to pay all obligations incurred in connection with such Projects, including debt service.

The Assignment Agreements provide that, subject only to the Participants' rights under the Net Billing Agreements, Energy Northwest assigns to Bonneville any rights which it now has or may hereafter obtain in project capability by a reversion of any Participant's share in Project capability to Energy Northwest or by any other means. Bonneville accepted this assignment, and in the event that any Participant is determined not to be obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agrees to pay directly to Energy Northwest the amounts that would have been payable under the Net Billing Agreements for such Project capability.

The Assignment Agreements are designed to assure that Bonneville will obtain any interest Energy Northwest has or may hereafter obtain in Project capability, subject only to the Participants' rights and obligations under the Net Billing Agreements, and that the same economic and practical consequences will result for Bonneville and Energy Northwest as if Bonneville had acquired such interest in Project capability pursuant to the assignment of Project capability contained in the Net Billing Agreements.

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**SUMMARY OF CERTAIN PROVISIONS
OF ELECTRIC REVENUE BOND RESOLUTIONS
AND SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS**

The following summary is an outline of certain provisions contained in the Electric Revenue Bond Resolutions and the Supplemental Electric Revenue Bond Resolutions and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Electric Revenue Bond Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the Trustee. Capitalized terms not otherwise defined in this Appendix H-1 shall have the meanings ascribed to them in this Official Statement.

Definitions

"*Authorized Purpose*" shall mean any one or more of the purposes described in Section 201 of the Electric Revenue Bond Resolutions.

"*Bank Bond"* shall mean any Electric Revenue Bond owned by the Related Credit Issuer or its permitted assigns in connection with the provision of moneys under the Related Credit Facility.

"*Code*" shall mean the Internal Revenue Code of 1986, as amended and supplemented from time to time, and the applicable temporary, proposed, or final regulations promulgated by the United States Treasury Department thereunder or under the Internal Revenue Code of 1954, as amended.

"*Comparable Treasury Issue*" means the U.S. Treasury security selected by a Reference Dealer as having a maturity comparable to the remaining term of the Columbia 2006-D (Taxable) Bonds to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Columbia 2006-D (Taxable) Bonds.

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

"*Credit Facility*" shall mean a letter of credit, line of credit, insurance policy, surety bond, standby bond purchase agreement or standby payment agreement or similar obligation or instrument or any combination of the foregoing issued by a bank, insurance company or similar financial institution or by the parent corporation of any of the foregoing or by the State or the Federal Government or any agency, authority, instrumentality or subdivision thereof, including, without limitation, the Administrator.

"*Debt Service Deposit Date*" shall mean any date on which a deposit is required to be made into the related Debt Service Fund by each Electric Revenue Bond Resolution or any Supplemental Electric Revenue Bond Resolution.

"*Defeasance Obligations*" shall mean (a) any of the obligations described in clause (i) of the definition of Investment Securities, (b) Refunded Municipal Obligations, and (c) with respect to any Series of Electric Revenue Bonds, such other obligations as are described in the Supplemental Electric Revenue Bond Resolutions authorizing such Series. The Supplemental Electric Revenue Bond Resolutions authorizing the Series 2006 Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2006 Bonds, any "Government Obligations" as that term is defined in Chap. 39.53 RCW and as it may be hereafter amended.

"Electric Revenue Bond Resolution" shall mean Resolution No. 835, adopted on November 23, 1993, as amended and supplemented, Resolution No. 1042, adopted on October 23, 1997, as amended and supplemented, and Resolution No. 838, adopted on November 23, 1993, as amended and supplemented.

"*Engineer*" shall mean any nationally recognized independent engineer or engineering firm appointed by Energy Northwest, and may be the Consulting Engineer appointed pursuant to Resolutions Nos. 769, 640 and 775.

"Government Obligations" means (a) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (b) bonds, debentures, notes, participation certificates, or other obligations issued by the banks for cooperatives, the federal intermediate credit bank, the federal home loan bank system, the export-import bank of the United States, federal land banks, or the federal national mortgage association; (c) public housing bonds and project notes fully secured by contracts with the United States; and (d) obligations of financial institutions insured by the federal deposit insurance corporation or the federal savings and

loan insurance corporation, to the extent insured or to the extent guaranteed as permitted under any provision of state law, as such definition may be amended.

"*Investment Securities*" shall mean any of the following, if and to the extent that the same are legal for the investment of funds of Energy Northwest:

(i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America;

(ii) obligations of any agency, subdivision, department, division or instrumentality of the United States of America, including, without limitation, the Federal Home Loan Mortgage Corporation, the Federal Agricultural Mortgage Corporation, the Student Loan Marketing Association and the International Bank for Reconstruction and Development; or obligations fully guaranteed as to interest and principal by any agency, subdivision, department, division or instrumentality of the United States of America;

(iii) direct obligations of, or obligations guaranteed as to principal and interest by, any state or direct obligations of any agency or public authority thereof, insured or uninsured, provided such obligations are rated, at the time of purchase, in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(iv) bank time deposits evidenced by certificates of deposit and bankers' acceptances issued by any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), provided that such time deposits and bankers' acceptances (a) do not exceed at any one time in the aggregate five percent (5%) of the total of the capital and surplus of such bank or trust company, or (b) are secured by obligations described in items (i) or (ii) of this definition of Investment Securities, which such obligations at all times have a market value at least equal to such time deposits so secured;

(v) repurchase agreements with (1) any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), or (2) any securities broker which is a member of the Securities Investor Protection Corporation, which such agreements are secured by securities which are obligations described in items (i) or (ii) of this definition of Investment Securities, provided that each such repurchase agreement (a) is in commercially reasonable form and is for a commercially reasonable period, and (b) results in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the repurchaser) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest; provided that such securities acquired pursuant to such repurchase agreements shall be valued at the lower of the then current market value of such securities or the repurchase price thereof set forth in the applicable repurchase agreement;

(vi) certificates or other obligations that evidence ownership of the right to payments of principal of or interest on obligations of the United States of America or any state of the United States of America or any political subdivision thereof or any agency or instrumentality of the United States of America or any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a Trustee under the Electric Revenue Bond Resolutions, and provided further that, in the case of certificates or other obligations that evidence ownership of the right to payments of principal or interest on obligations of a state or political subdivision, the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which shall be rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(vii) investment agreements rated in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds or the long-term unsecured debt obligations of the issuer of which are rated in one of the two highest rating categories by the respective agency rating such investment agreements or investment agreements which result in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the counterparty to the investment agreement) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest;

(viii) bankers' acceptances drawn on and accepted or guaranteed by a commercial bank rated in either of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(ix) commercial paper rated, at the time of purchase, in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(x) shares of any publicly offered mutual fund of the type commonly known as a "money market fund" that, at the time of investment, has at least 85% of its assets directly invested in securities of the type described in items (i), (ii) and (iii) of this definition of Investment Securities; and

(xi) such other investments with respect to any Series of Electric Revenue Bonds as shall be specified in the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"Outstanding" or "outstanding" shall mean, as if any date, (a) when used with reference to Electric Revenue Bonds, all Electric Revenue Bonds theretofore or thereupon issued or authorized pursuant to the Electric Revenue Bond Resolution, except: (i) any Electric Revenue Bonds paid in full, surrendered for cancellation or cancelled at or prior to such date (including any Bond held in escrow pending settlement of any tender offer by Energy Northwest or the Trustee on its behalf, but excluding any Option Bond so held pending settlement of a purchase on a tender date); and (ii) Electric Revenue Bonds in lieu of or in substitution for which other Electric Revenue Bonds shall have been authenticated or delivered pursuant to the Electric Revenue Bond Resolution; and (iii) Electric Revenue Bonds deemed to be no longer outstanding under the Electric Revenue Bond Resolution as provided therein or under any Supplemental Resolution authorizing the issuance of a Series of Electric Revenue Bonds, (b) when used with reference to Prior Lien Bonds shall have the meaning assigned to such term in the Prior Lien Resolution, and (c) when used with reference to Subordinate Lien Obligations shall have the meaning assigned to such term by the instrument or instruments under which such Subordinate Lien Obligations are issued.

"*Parity Debt*" shall mean bonds, notes or other obligations issued under a resolution or resolutions authorized pursuant to the Electric Revenue Bond Resolutions, the Electric Revenue Bonds and any Parity Reimbursement Obligation.

"*Parity Reimbursement Obligation*" shall mean a reimbursement obligation the payment of which, pursuant to the provisions of a Supplemental Electric Revenue Bond Resolution, is secured as to payment by the pledge created by the Electric Revenue Bond Resolutions.

"*Payment Agreement*" shall mean a written agreement which provides for an exchange of payments based on interest rates, or for ceilings or floors on such payments, or an option on such payments, or any combination, entered into on either a current or forward basis.

"*Payment Date*" shall mean each date on which interest shall be due and payable and each date on which both interest shall be due and payable and a scheduled Principal Installment (whether by payment of principal scheduled to mature or a sinking fund installment to be paid) shall be required to be made on any of the outstanding Electric Revenue Bonds according to their respective terms.

"*Principal Installment*" shall mean, as of any date of calculation and with respect to any Series or Subseries, as the case may be, (a) the principal amount of Electric Revenue Bonds (including any amount designated in, or determined pursuant to, the applicable Supplemental Electric Revenue Bond Resolution, as the "principal amount" with respect to any bonds) of such Series or subseries scheduled to mature on a certain future date for which no sinking fund installments have been established, or (b) the unsatisfied balance of sinking fund installments scheduled to be paid on a certain future date for Electric Revenue Bonds of such Series or subseries, or (c) if such future dates coincide as to different Electric Revenue Bonds of such Series or subseries, the sum of such principal amount and such unsatisfied balance scheduled to mature or to be paid on such future date; in each case in the amounts and on the dates as provided in the applicable Supplemental Electric Revenue Bond Resolution authorizing such Series or subseries regardless of any retirement of Electric Revenue Bonds except pursuant to Section 505 of the Electric Revenue Bond Resolutions or (d) that portion of a Parity Reimbursement Obligation which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid or that portion of a Parity Reimbursement Obligation payable on a certain future date which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid.

"Prior Lien Bonds" shall mean, collectively, the bonds heretofore or hereafter issued pursuant to the Prior Lien Resolutions.

"Prior Lien Resolutions" shall mean, collectively, Resolution No. 769, adopted on September 18, 1975, as amended and supplemented, Resolution No. 640, adopted on June 26, 1973, as amended and supplemented, and Resolution No. 775, adopted on December 3, 1975, as amended and supplemented.

"*Rating Agency*" shall mean Fitch, Inc. ("Fitch"), Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

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

"*Reference Treasury Dealer Quotations*" means, with respect to each Reference Dealer and any redemption date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to Energy Northwest and Bonneville by such Reference Dealer at 5:00 p.m. (New York time) on the third business day preceding such redemption date.

"Refunded Municipal Obligations" shall mean obligations of any state, the District of Columbia or possession of the United States of America or any political subdivision thereof, which obligations are rated in the highest rating category by at least two nationally recognized rating agencies and provision for the payment of the principal of and interest on which shall have been made by deposit with a Trustee or escrow agent of direct obligations of, or obligations guaranteed by, the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or any state, the District of Columbia or possession thereof in the capacity as custodian, the maturing principal of and interest on which when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession or political subdivision.

"*Reserve Account Requirement*" shall mean, with respect to a Series of Electric Revenue Bonds, the amount, if any, prescribed by the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Reserve Guaranty*" shall mean an insurance policy or surety bond provided by an insurer whose claims-paying ability is rated in either of the two highest rating categories by at least two nationally recognized rating agencies, or a letter of credit or other similar Credit Facility the long-term unsecured debt of the issuer of which is rated in either of the two highest rating categories by at least two nationally recognized rating agencies.

"Revenues" shall mean all income, revenues, receipts and profits derived by Energy Northwest through the ownership and operation by Energy Northwest of the related Project and all other moneys required to be deposited in the Revenue Fund created pursuant to the related Prior Lien Resolution.

"*Subordinate Lien Obligation*" shall mean any bond, note, certificate, warrant or other evidence of indebtedness of Energy Northwest authorized by the Electric Revenue Bond Resolution.

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

Effect of Amendments Adopted March 9, 2001 (Project 1, Columbia and Project 3)

The Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, amend the Project 1, Columbia and Project 3 Electric Revenue Bond Resolutions, respectively, to add a covenant to the effect that, from and after the issuance of the Series 2001-A Bonds, Energy Northwest will not issue or authorize the issuance of Prior Lien Bonds under the related Prior Lien Resolution and shall not otherwise create any other special fund or funds for the payment of bonds, warrants or other obligations which will rank on a parity with the pledge and lien on the Revenues created by such Prior Lien Resolution.

Each Supplemental Resolution also amends the related Electric Revenue Bond Resolution to add a definition of the term "Energy Northwest" and to change the definition of the term "System," as follows:

"Energy Northwest" shall mean the joint operating agency organized and existing under the provisions of the Act and formerly known as the Washington Public Power Supply System.

"System" shall mean Energy Northwest.

The Project 1 Supplemental Resolution further amends the Project 1 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 1 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 1 Electric Revenue Bond Supplemental Resolution, shall be known as "Energy Northwest Project 1 Electric Revenue Bonds."

The Columbia Supplemental Resolution further amends the Columbia Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution, from and after the date of adoption of the Columbia Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Columbia Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Columbia Generating Station Electric Revenue Bonds."

The Project 3 Supplemental Resolution further amends the Project 3 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 3 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 3 Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Project 3 Electric Revenue Bonds."

Electric Revenue Bond Resolutions to Constitute Contract (Section 103)

Each Electric Revenue Bond Resolution constitutes a contract between Energy Northwest and the owners from time to time of the Electric Revenue Bonds, and the issuer of a Credit Facility, if any, relating to such subseries of Electric Revenue Bonds; and the pledge made in each related Electric Revenue Bond Resolution and the covenants and agreements therein set forth to be performed on behalf of Energy Northwest shall be for the equal benefit, protection and security of the owners of any and all of the Electric Revenue Bonds and the issuer of any related Credit Facility where the obligation of Energy Northwest to reimburse such issuer is a Parity Reimbursement Obligation, each of which, regardless of time or times of maturity or due dates, shall be of equal rank without preference, priority or distinction of the Electric Revenue Bonds over any other thereof except as expressly provided in or permitted by the Electric Revenue Bond Resolutions.

Authorization of Bonds (Section 201)

The Project 1 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 1 Electric Revenue Bonds," the Columbia Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Columbia Electric Revenue Bonds," and the Project 3 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 3 Electric Revenue Bonds."

The Electric Revenue Bonds may be issued under each Electric Revenue Bond Resolution from time to time in series, which may consist of two or more subseries, pursuant and subject to the terms, conditions and limitations of the Electric Revenue Bond Resolutions and any Supplemental Electric Revenue Bond Resolutions providing for the issuance of Electric Revenue Bonds, in such amounts as may be determined by Energy Northwest, for one or more of the following purposes: (i) refunding any Outstanding Prior Lien Bond, any Outstanding Electric Revenue Bond or any Outstanding Subordinate Lien Obligation; (ii) the payment, or reimbursement of Energy Northwest for the payment, of the costs of the acquisition, construction or installation of additional facilities or modifications to the related Project in compliance with the order or decision of any State or Federal agency or authority having competent jurisdiction; (iii) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of making renewals, repairs, replacements, improvements or betterments to the related Project, including costs associated with the upgrading of the output capacity of the related Project, including expenses incurred in connection with the upgrading of any operating license in connection therewith; (iv) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of capital additions, improvements or betterments to the related Project necessary to achieve design capability; (v) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of (1) decommissioning the related Project or (2) restoring the site of the related Project, in compliance with applicable Federal or State law or any order or decision of any State or Federal agency or authority having competent jurisdiction; (vi) payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of purchasing fuel for the related Project; (vii) providing funds for deposit into the Reserve Accounts or any other reserves established by any Supplemental Electric Revenue Bond Resolution for the payment of the principal of or interest on the Series of Electric Revenue Bonds authorized thereby and paying the costs incident to the issuance of such Series of Electric Revenue Bonds; and (viii) the payment, or the reimbursement of Energy Northwest for the payment, of the costs of any other purpose permitted by law.

Pledge Effected by the Electric Revenue Bond Resolutions (Section 202)

Energy Northwest pledges for the payment of the principal or redemption price of and interest on the Electric Revenue Bonds in accordance with their terms and the provisions of the Electric Revenue Bond Resolutions (i) the proceeds of the sale of the Electric Revenue Bonds pending application thereof in accordance with the provisions of the applicable Electric Revenue Bond Resolution or of any applicable Supplemental Electric Revenue Bond Resolution, (ii) subject to the provisions of each Electric Revenue Bond Resolution, all revenues and (iii) the Debt Service Fund established by each Electric Revenue Bond Resolution, including the investments, if any, therein; provided, however, that, subject to each Electric Revenue Bond Resolution, amounts on deposit to the credit of any Reserve Account in the Debt Service Funds are pledged only to the Series of Electric Revenue Bonds for which such Reserve Account was established pursuant to the Supplemental Electric Revenue Bond Resolutions authorizing such Series and may be applied only to pay the principal or redemption price, if any, of and interest on the Electric Revenue Bonds of such Series.

Except as may be otherwise provided in the Electric Revenue Bond Resolutions or in the Supplemental Electric Revenue Bond Resolutions authorizing a Series of Electric Revenue Bonds, the Electric Revenue Bonds of each such Series shall be equally and ratably payable and secured under the related Electric Revenue Bond Resolution without priority by reason of the date of adoption of the Supplemental Electric Revenue Bond Resolutions providing for their issuance or by reason of their Series or subseries, number or date, date of issue, execution, authentication or sale thereof, or otherwise.

The revenues and other moneys pledged and received by Energy Northwest shall immediately be subject to the lien of the pledge made by Energy Northwest under each Supplemental Electric Revenue Bond Resolution without any physical delivery or further act, and the lien of the pledge shall be valid and binding as against any parties having claims of any kind in tort, contract or otherwise against Energy Northwest, irrespective of whether such parties have notice thereof.

Refunding Bonds (Section 204)

All Electric Revenue Bonds issued to refund Outstanding Electric Revenue Bonds shall be authenticated and delivered by the Trustee only upon receipt by it, in addition to other documents required by the Electric Revenue Bond Resolutions (and in addition to further documents required by the provisions of any Supplemental Electric Revenue Bond Resolutions), of:

(i) irrevocable instructions to the Trustee, satisfactory to it, to give due notice of redemption of all the Electric Revenue Bonds to be redeemed on a redemption date or dates specified in such instructions;

(ii) if the Electric Revenue Bonds to be refunded are not to be redeemed within the next succeeding 90 days, irrevocable instructions to the Trustee, satisfactory to it, to give due notice of any refunding of such Electric Revenue Bonds on a specified date prior to their maturity, as provided in Article VI of each Electric Revenue Bond Resolution or in the Supplemental Electric Revenue Bond Resolution which authorized such Electric Revenue Bonds to be refunded, and Section 1101 of each Electric Revenue Bond Resolution;

(iii) either (A) moneys (which may include all or a portion of the proceeds of the refunding Electric Revenue Bonds to be issued) in an amount sufficient to effect payment of the principal or the redemption price of the Electric Revenue Bonds to be refunded, together with accrued interest on such Electric Revenue Bonds to the maturity or redemption date thereof, as the case may be, or (B) Defeasance Obligations in such principal amounts, of such maturities, bearing such interest and otherwise having such terms and qualifications and any moneys, as shall be necessary to comply with the provisions of Section 1101 of each Electric Revenue Bond Resolution, which Defeasance Obligations and moneys shall be held in trust and used only as provided in Section 1101 of each Electric Revenue Bond Resolution; and

(iv) such further documents and moneys as are required by the provisions of each Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolutions.

In addition, all refunding Electric Revenue Bonds of a Series issued to refund outstanding Prior Lien Bonds shall be authenticated and delivered by the Trustee, upon receipt by the Trustee, in addition to other documents required by the Electric Revenue Bond Resolutions, of evidence satisfactory to it that:

(i) irrevocable instructions have been delivered to the Prior Lien Bond Fund Trustee to give due notice of payment or redemption of all the Project 1, Columbia or Project 3 Prior Lien Bonds to be redeemed prior to their respective maturity dates on the date specified in such instructions, all in accordance with either Resolution Nos. 769, 640 or 775, as the case may be; and

(ii) such further documents and moneys as are required by the provisions of the applicable Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolution.

Subordinate Obligations (Section 205)

Nothing contained in the Electric Revenue Bond Resolutions prohibits or prevents Energy Northwest from authorizing and issuing bonds, notes, certificates, warrants or other evidences of any indebtedness for any purpose relating to the Net Billed Projects payable as to principal and interest from the revenues subject and subordinate to the deposits and credits required to be made to the funds established under the Electric Revenue Bond Resolutions or from securing such bonds, notes, certificates, warrants or other evidences of indebtedness and the payment thereof by a lien and pledge on the revenues junior and inferior to the lien and the pledge on the revenues created by either Resolution Nos. 769, 640 or 775, as the case may be, and created by the Electric Revenue Bond Resolutions.

Credit Facilities (Section 208)

Electric Revenue Bond Supplemental Resolutions providing for the issuance of a Series of Electric Revenue Bonds may provide that Energy Northwest obtain or cause to be obtained Credit Facilities providing for payment of all or a portion of the purchase price or Principal Installment or Redemption Price of, or interest due or to become due on specified Electric Revenue Bonds of such Series or any Subseries thereof, or providing for the purchase of such Electric Revenue Bonds or a portion thereof by the issuer of the Credit Facilities, or providing, in whole or in part, for the funding of the Reserve Accounts pursuant to Section 505 of each Electric Revenue Bond Resolution, provided such Credit Facility is a Reserve Guaranty. In connection therewith, Energy Northwest may enter into agreements with the issuers of the Credit Facility to provide for the terms and conditions thereof, including the security, if any, to be provided to such issuers.

Energy Northwest may secure the applicable Credit Facility by an agreement providing for the purchase of the Electric Revenue Bonds secured thereby with such adjustments to the rate of interest, method of determining interest, maturity, or redemption provisions as specified in the Supplemental Electric Revenue Bond Resolutions. Interest with respect to any Series of Electric Revenue Bonds so secured shall be calculated for purposes of the Reserve Account Requirement for such Series by using the actual rate of interest or, if applicable, the Certified Interest Rate on the Electric Revenue Bonds prior to adjustment under such agreement. Energy Northwest may also agree to reimburse directly the issuers of the Credit Facilities for any amounts paid thereunder together with interest thereon. Energy Northwest may provide that any such obligations to reimburse shall be Parity Reimbursement Obligations. In addition, Energy Northwest may, in connection with any such Credit Facility, agree to pay the fees and expenses of, and other amounts payable to, the issuers of such Credit Facilities, the payment of which may be secured by pledges of revenues, funds and other moneys pledged pursuant to the Electric Revenue Bond Resolutions on a parity with the pledges created by the Electric Revenue Bond Resolutions.

The Bond Fund (Section 501)

The Bond Fund created for the related Series of Prior Lien Bonds shall be continued for so long as any related Prior Lien Bonds remain Outstanding. As soon as practicable after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will direct, in writing, the Bond Fund Trustee under the related Prior Lien Resolutions to deliver forthwith all moneys and securities held in the Bond Fund, except for amounts, if any, required to be held by said Bond Fund Trustee to provide for the payment of the principal (including sinking fund installments) of premium, if any, and interest on the Prior Lien Bonds and expenses of the Bond Fund Trustee, to Energy Northwest, who will deposit such moneys and securities in the General Revenue Fund.

Establishment of Funds (Section 502)

The following special trust funds are established by each Electric Revenue Bond Resolution:

(a) General Revenue Fund, to be held and maintained by Energy Northwest; and

(b) Debt Service Fund, to be held and maintained by the Trustee. The Debt Service Fund shall include a separate Debt Service Account for each Series of Electric Revenue Bonds and a separate subaccount for each subseries of Electric Revenue Bonds issued under each Electric Revenue Bond Resolution and each such Debt Service Account and subaccount shall be designated using the designation of the Series or subseries, if any, to which such Debt Service Account or subaccount relates.

The existence of such funds shall be continued for so long as any Electric Revenue Bonds remain outstanding. Energy Northwest may establish pursuant to Supplemental Electric Revenue Bond Resolutions authorizing the issuance of Electric Revenue Bonds, additional funds, accounts and subaccounts for the purposes designated in such Supplemental Electric Revenue Bond Resolutions.

Disposition of Revenues (Section 503)

So long as the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, Energy Northwest has obligated and bound itself irrevocably to pay, after first providing for all required deposits and payments under the respective Prior Lien Resolutions to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that Energy Northwest has insufficient funds to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt (including the Trustee) and to each person entitled thereto, as applicable, its pro rata share of the amounts available to Energy Northwest for such payments. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the 25th day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each debt service subaccount in the related Debt Service Account, from the revenues theretofore deposited in the Revenue Fund the amount, which, when added to the amount then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each scheduled sinking fund installment required to be paid and the amount of interest due and payable, or if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest, on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, provided to be so paid pursuant to the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

On and after the date on which there shall be no Prior Lien Bonds outstanding, Energy Northwest covenants and agrees that it will pay into each General Revenue Fund as promptly as practical after receipt thereof all revenues and all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

General Revenue and Debt Service Funds (Sections 504 and 505)

General Revenue Fund. The amounts on deposit in each General Revenue Fund shall be trust funds in the hands of Energy Northwest and, subject to certain provisions described herein, shall be used and applied as provided in the applicable Electric Revenue Bond Resolution solely for the purpose of paying principal and interest on Parity Debt, the cost of operating and maintaining the related Project and paying all other costs, charges and expenses in connection with the costs of making repairs, renewals, replacements, additions, betterments and improvements to and extensions of the related Project and for purposes of paying all other charges and obligations against said revenues, income, receipts, profits and other moneys of whatever nature now or hereafter imposed thereon by law or contract, to the payment of which for such purposes said revenues and other moneys are pledged, including amounts required to be paid to the issuers of any Credit Facility pursuant to the provisions of any related Supplemental Electric Revenue Bond Resolution.

After the date on which there are no Prior Lien Bonds Outstanding, Energy Northwest shall pay, from the moneys on deposit in each General Revenue Fund, to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that the moneys on deposit in the General Revenue Fund shall be insufficient to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt and to each person thereof entitled thereto, as applicable, its pro rata share of the amounts on deposit in the General Revenue Fund. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the last Business Day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each relevant debt service subaccount in the related Debt Service Account, the amount, which, when added to the amount, if any, then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each sinking fund installment required to be paid, and the amount of interest due and payable, or, if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, required to be so paid pursuant to the provisions of the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the applicable Electric Revenue Bond Resolution to be so deposited.

Debt Service Fund. The Trustee shall, for each Series or Subseries of Electric Revenue Bonds Outstanding, pay from the moneys on deposit in each relevant Debt Service Account or subaccount of each Debt Service Fund (i) the amounts required for the payment of the principal, if any, due on each Payment Date and (ii) the amount required for the payment of interest due on each Payment Date and (iii) on any redemption date the amounts required to pay the redemption price of the Electric Revenue Bonds to be redeemed on such date, unless the payment of such redemption price shall be otherwise provided, and (iv) on any redemption date or date of purchase, the amounts required for the payment of accrued interest on Electric Revenue Bonds to be redeemed or purchased on such date unless the payment of such accrued interest shall be otherwise provided and (v) at the times and in the manner provided in the related Supplemental Electric Revenue Bond Resolution and the agreements between Energy Northwest and any issuer of a Credit Facility or counterparty to any Payment Agreement, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts provided to be so paid.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, Energy Northwest may, prior to the forty-fifth day preceding the due date of any sinking fund installment purchase Electric Revenue Bonds of the Series or Subseries, as the case may be, and maturity for which such sinking fund installment was established, at prices (including any brokerage and other charges) not exceeding the redemption price payable for such Electric Revenue Bonds when such Electric Revenue Bonds are redeemable by application of such sinking fund installment plus unpaid interest accrued to the date of purchase, such purchases to be made by the Trustee as directed in writing by an authorized officer of Energy Northwest.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, upon the purchase or redemption (other than by application of sinking fund installments) of any Electric Revenue Bond, an amount equal to the principal amount of the Electric Revenue Bond so purchased or redeemed shall be credited toward the sinking fund installments thereafter to become due as directed in writing by an authorized officer of Energy Northwest.

Energy Northwest may, at its option, in lieu of depositing all or any part of the sinking fund installments into each relevant Debt Service Account or subaccount thereof of each Debt Service Fund, furnish the Trustee with a Certificate of an authorized officer stating that Energy Northwest has purchased for cancellation term bonds of a Series or Subseries of Electric Revenue Bonds in the principal amount, and bearing the numbers, specified therein, and that said term bonds have not been previously included in any such Certificate; and thereupon the sinking fund installments with respect to the term bonds of such Series or subseries, as the case may be, may be reduced by the principal amount of such term bonds canceled, as provided by such Certificate.

Unless otherwise provided for a Series of Electric Revenue Bonds or subseries thereof, as the case may be, in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, as soon as practicable after the forty-fifth day preceding the due date of any such sinking fund installment, the Trustee shall proceed to call for redemption, pursuant to Article IV of each Electric Revenue Bond Resolution or the applicable Supplemental Electric Revenue Bond Resolutions, as the case may be, on such due date, Electric Revenue Bonds of the Series or subseries, as the case may be, and maturity for which such sinking fund installment was established in such amount as shall be necessary to complete the retirement of the principal amount specified for such sinking fund installment of the Electric Revenue Bonds of such Series or subseries, as the case may be, and maturity. The Trustee shall so call such Electric Revenue Bonds for redemption whether or not it then has moneys in each Debt Service Account or subaccount thereof of each Debt Service Fund established for such Series or subseries, as the case may be, sufficient to pay the applicable redemption price thereof on the redemption date. The Trustee shall apply to the redemption of the Electric Revenue Bonds on each such redemption date, the amount required for the redemption of such Electric Revenue Bonds.

Bond Proceeds Funds (Section 507)

The Supplemental Electric Revenue Bond Resolution providing for the issuance of any Series of Electric Revenue Bonds (exclusive of Refunding Bonds) will create and establish one or more special trust funds into which the proceeds of such Series of Electric Revenue Bonds will be deposited and from which such proceeds will be disbursed to pay the Costs of the Authorized Purpose or Purposes for which such Series of Electric Revenue Bonds were issued (unless such Supplemental Electric Revenue Bond Resolution will provide for the deposit of such proceeds in one or more of such funds theretofore created and established). Each such fund (a “Bond Proceeds Fund”) will be held in trust by Energy Northwest, for the benefit of the owners of the Electric Revenue Bonds pending application thereof in accordance with the terms of the related Supplemental Electric Revenue Bond Resolution. Payments from Bond Proceeds Fund will be as specified in the Supplemental Electric Revenue Bond Resolution authorizing the issuance of a related Series of Electric Revenue Bonds.

Amounts on deposit in any Bond Proceeds Fund, pending their application as provided in the Supplemental Electric Revenue Bond Resolution creating such Bond Proceeds Fund, will be subject to a prior and paramount lien and charge in favor of the owners of the Electric Revenue Bonds, and the owners of the Electric Revenue Bonds will have a valid claim on such moneys for the further security of the Electric Revenue Bonds until paid out or transferred as herein provided.

Investment of Funds (Section 508)

Moneys held in each Debt Service Fund shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee upon request of Energy Northwest (promptly confirmed in writing) solely in Investment Securities which shall mature or be subject to redemption at the option of the owner thereof on or prior to the respective dates when the moneys therein will be required for the purposes intended. However, moneys in each Reserve Account in each Debt Service Fund not required for immediate disbursement for the purpose for which said Account is created shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee at the direction of Energy Northwest (promptly confirmed in writing) solely in, and obligations credited to each Reserve Account shall be, Investment Securities which, unless otherwise provided in the related Supplemental Electric Revenue Bond Resolution, shall mature or be subject to redemption at the option of the owner thereof on or prior to the last maturity date of the related Series of Electric Revenue Bonds. The Trustee shall not be liable for any depreciation in value of any such investments. For the purpose of Section 508 of the Electric Revenue Bond Resolutions, the term “Investment Securities” shall be limited to obligations described in clauses (i) and (v) of the definition of Investment Securities.

Nothing in the Electric Revenue Bond Resolutions shall prevent any Investment Securities acquired as investments of funds held thereunder from being issued or held in book-entry form.

Valuation or Sale of Investments (Section 509)

Investment Securities in any fund or account created under the provisions of each Electric Revenue Bond Resolution shall be deemed at all times to be part of such fund or account and any profit realized from the liquidation of such investment shall be credited to such fund or account and any loss resulting from liquidation of such investment shall be charged to such fund or account. So long as the Project 1, Columbia or Project 3 Prior Lien Bonds shall remain Outstanding, any net profits remaining after accumulating the sum of all profits realized and losses suffered from the liquidation of such investments in any fund or account shall be retained in the related Debt Service Accounts (or subaccounts) of each Debt Service Fund, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing Series of Electric Revenue Bonds; provided, however, that if the money and value of investments in any Reserve Account in each Debt Service Fund shall exceed the applicable Reserve Account Requirement for the Series of Electric Revenue Bonds for which such Reserve Account was established, the amount of such excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest to each Debt Service Account established for such Series, unless otherwise provided in Supplemental Electric Revenue Bond Resolutions authorizing such Series of Electric Revenue Bonds. After the date on which there shall be no Project 1, Columbia or Project 3 Prior Lien Bonds outstanding, any such net profits or excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest, or paid to, or retained in, each General Revenue Fund.

In computing the amount in any fund or account, Investment Securities therein shall be valued at cost or, if purchased at a premium or discount, at their amortized value. Any such computation shall include accrued interest on the Investment Securities paid as part of the purchase price thereof and not repaid. Such computation shall be made annually on June 30th for all funds and accounts established pursuant to the Electric Revenue Bond Resolutions and at such other times as Energy Northwest shall determine or as may be required by the Electric Revenue Bond Resolutions.

Except as otherwise provided in the Electric Revenue Bond Resolutions, the Trustee, as directed by an authorized officer of Energy Northwest (promptly confirmed in writing), shall use its best efforts to sell at the best price obtainable, or present for redemption, any Investment Securities held by the Trustee in any fund or account whenever it shall be necessary, and upon oral request (promptly confirmed in writing) from an authorized officer of Energy Northwest in order to provide moneys to meet any payment or transfer from such fund or account. The Trustee shall not be liable or responsible for any loss resulting from any such investment, sale, liquidation or presentation for investment made in the manner provided above.

Subject to the foregoing limitations, any moneys held by Energy Northwest or the Trustee under a particular Electric Revenue Bond Resolution may be pooled in order to make any purchase of Investment Securities or deposit of moneys held under such Electric Revenue Bond Resolution, which purchases or deposits are otherwise permitted thereunder; provided, however, that Energy Northwest and the Trustee shall at all times keep accurate and complete records of the Investment Securities so purchased and deposits so made in sufficient detail as will permit the application of such Investment Securities and deposits, and the proceeds thereof, solely for the purposes, at the times and in the manner provided in each Electric Revenue Bond Resolution.

Qualifications and Appointment of Trustee; Resignation or Removal Thereof; Successor Thereto (Section 601)

In the Supplemental Electric Revenue Bond Resolution providing for the issuance of the initial Series of Electric Revenue Bonds, Energy Northwest shall appoint a Trustee (the "Trustee") to hold and administer the Funds and Accounts created and established in each Electric Revenue Bond Resolution. The Trustee will be a commercial bank with trust powers or trust company with capital stock, surplus and undivided profits aggregating in excess of $50,000,000. The Trustee may be removed at the request of or upon the affirmative vote of (i) the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, or (ii) a majority of the members of the Executive Board of Energy Northwest, provided, however, that the Trustee may not be removed pursuant to the preceding clause (ii) upon the occurrence of an Event of Default or while such an Event of Default shall be continuing: provided further, that any removal will not take effect until the appointment of a successor and the acceptance by such successor in accordance with each Electric Revenue Bond Resolution.

In the event of the removal pursuant to clause (i) of the preceding sentence, resignation, disability or refusal to act of the Trustee, a successor may be appointed by the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, excluding any Electric Revenue Bonds held by or for the account of Energy Northwest, and such successor shall have all the powers and obligations of the Trustee under each Electric Revenue Bond Resolution theretofore vested in its predecessor; provided, that unless a successor Trustee has been appointed by the owners of Electric Revenue Bonds as aforesaid, Energy Northwest by a duly executed written instrument signed by a majority of the members of the Executive Board will concurrently appoint a Trustee to fill such vacancy until a successor Trustee will be appointed by the owners of Electric Revenue Bonds as authorized in this paragraph. Any successor Trustee appointed by Energy Northwest pursuant to this paragraph will, immediately and without further act, be superseded by a Trustee so appointed by the owners of Electric Revenue Bonds.

In the event of the removal of the Trustee pursuant to clause (ii) above, Energy Northwest will appoint a successor Trustee.

Any Trustee may resign at any time by giving not less than 180 days' notice to Energy Northwest in writing and to the Bondholders by publishing a notice of resignation in an Authorized Newspaper once within 10 days after the giving of such notice to the Energy Northwest; provided, however, that such resignation shall not take effect until the appointment of a successor and the acceptance of such successor in accordance with this Resolution.

The resigning Trustee, if within 50 days after the publication of notice of its resignation no successor Trustee has been appointed and accepted such appointment, may petition any court of competent jurisdiction for the appointment of a successor Trustee, or any owner of a Bond who has been an owner of a Bond for at least six months may, on behalf of such owner and others similarly situated, petition any such court for the appointment of a successor Trustee. Such court may thereupon, after such notice, if any, appoint a successor Trustee having the qualifications required hereby.

In case at any time any of the following shall occur: (i) any Trustee ceases to be eligible in accordance with the provisions of each Electric Revenue Bond Resolution and fails to resign after written request therefor has been given to such Trustee by Energy Northwest or by any owner of a Bond who has been a bona fide owner of a Bond for at least six months, or (ii) any Trustee becomes incapable of acting, or is adjudged a bankrupt or insolvent, or a receiver of such Trustee or of its property is appointed, or any public officer takes charge or control of such Trustee or of its property or affairs for the purpose of rehabilitation, conservation or liquidation, or (iii) any Trustee neglects or fails in the performance of its duties under each Electric Revenue Bond Resolution, then, in any such case, Energy Northwest may remove such Trustee by an instrument in writing signed by an Authorized Officer or any such owner of a Bond may, on behalf of himself and all others similarly situated, petition any court of competent jurisdiction for the removal of such Trustee. Such court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, remove such Trustee.

Any successor Trustee shall meet the qualifications of each Electric Revenue Bond Resolution. Such successor Trustee will execute, acknowledge and deliver to its predecessor, and also to Energy Northwest, an instrument in writing accepting such appointment under each Electric Revenue Bond Resolution, and thereupon such successor Trustee, without any further acts, deed or conveyance, shall become fully vested with all the rights, powers, trusts, duties and obligations of its predecessor in trust under each Electric Revenue Bond Resolution, with like effect as if originally named as Trustee; but such predecessor will, nevertheless, on the written request of Energy Northwest or such successor Trustee, execute and deliver an instrument transferring to such successor Trustee all rights, powers, trusts, duties and obligations of such predecessor in trust under each Electric Revenue Bond Resolution and will deliver all moneys held by it to such successor Trustee, together with an accounting of funds held by it under each Electric Revenue Bond Resolution. The successor Trustee will have no responsibility for the acts of the predecessor Trustee.

Upon acceptance of appointment by the successor Trustee, as provided in this Section, Energy Northwest will publish notice of the succession of such Trustee to the trusts hereunder at least once in an Authorized Newspaper. If Energy Northwest fails to publish such notice, within 10 days after acceptance of appointment by the successor Trustee, the successor Trustee will cause such notice to be published at the expense of Energy Northwest.

Any corporation into which a Trustee may be merged or with which it may be consolidated, or any corporation resulting from any merger or consolidation to which a Trustee is a party, or any corporation to which a Trustee may sell or transfer all or substantially all of its corporate trust business, will be the successor Trustee under each Electric Revenue Bond Resolution without the execution or filing of any paper or any further act on the part of the parties to each Electric Revenue Bond Resolution; provided such corporation meets the qualifications of each Electric Revenue Bond Resolution.

Certain Covenants (Article VII)

Energy Northwest covenants and agrees with the purchasers and owners of all Electric Revenue Bonds issued pursuant to the Electric Revenue Bond Resolution to the following:

Compliance with Prior Lien Resolutions. So long as any of the Project 1 Prior Lien Bonds, the Columbia Prior Lien Bonds or the Project 3 Prior Lien Bonds are Outstanding, Energy Northwest shall comply in all respects with each of the provisions, covenants and agreements of or contained in Resolution Nos. 769, 640 and 775, respectively.

Concerning the Agreements and Prior Lien Resolutions. So long as any of the Electric Revenue Bonds are Outstanding, Energy Northwest will not (i) voluntarily consent to or permit any rescission of or consent to any amendment to or otherwise take any action under or in connection with any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds or (ii) voluntarily consent to or permit any rescission of or consent to any amendment to or modification of or otherwise take any action under or in connection with, each Project Agreement in the case of Columbia, each Assignment Agreement, each Property Disposition Agreement or each 1989 Letter Agreement which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds; and Energy Northwest shall perform all of its obligations under said Agreements and shall take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Electric Revenue Bonds afforded by the provisions of said Agreements. Energy Northwest will not, so long as any Project 1, Columbia or Project 3 Prior Lien Bonds remain Outstanding, consent to or agree to any change, amendment or modification of the Prior Lien Resolutions, respectively, which would in any way or manner prejudice or affect adversely the rights or interests of the owners of the Electric Revenue Bonds.

Encumbrance or Disposition of Project Properties; Termination of Projects. On and after the date on which the Prior Lien Bonds are no longer Outstanding, Energy Northwest will not sell, mortgage, lease or otherwise dispose of any properties of the related Project, or permit the sale, mortgage, lease or other disposition thereof, except as provided below.

(i) Energy Northwest may sell, lease or otherwise dispose of all or any portion of the works, plants and facilities of a Project and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operation of a Project, provided, however, that if the original costs of the properties so to be disposed of was in excess of $5,000,000, an Engineer shall first certify that the properties to be disposed of are unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operations of a Project; provided, however, no such certification shall be required if such sale or other disposition takes place after a Project has been terminated. Money received by Energy Northwest as the proceeds of any such sale, lease or other disposition of all or any portion of the properties of a Project shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds; provided, however, that if such sale, lease or other disposition of all or any portion of the properties of a Project is in connection with the replacement of such properties, all moneys received from such partial disposition of property may be transferred to the respective General Revenue Funds.

(ii) Energy Northwest may sell, lease or otherwise dispose of fuel for a price not less than the lesser of the cost to Energy Northwest thereof or the fair market value thereof at the time of such sale, lease or other disposition; provided, that any moneys received by Energy Northwest as proceeds of any such sale, lease or purchase shall be either transferred to the respective General Revenue Funds or used for the purchase or redemption of Electric Revenue Bonds.

(iii) In the event that the ownership of the properties of a Project or any part thereof shall be transferred from Energy Northwest through the operation of law, any moneys received by Energy Northwest as a result of any such transfer shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds.

(iv) Energy Northwest may terminate a Project at any time. Any moneys received by Energy Northwest from the disposition of the properties of a Project so terminated may be applied to the payment of the cost of decommissioning such Project including the cost of restoring the site thereof, and any amounts so received not required to pay such costs shall be applied as provided in paragraph (iii) above or in each Electric Revenue Bond Resolution.

Nothing contained in the Electric Revenue Bond Resolutions shall be construed to prevent Energy Northwest from constructing as a separate utility system any additional generating unit or units on or near the site of any Project, and using facilities of a Project in connection with the construction or operation therewith without compensation therefor; provided, however, that an Engineer shall certify to Energy Northwest and the Trustee that such use will not adversely affect the operations of the applicable Project or interfere with the performance by Energy Northwest of its obligations under the Electric Revenue Bond Resolutions; and provided further, however, that any compensation received by Energy Northwest on account of any such use shall be paid into the respective General Revenue Funds.

Notwithstanding the provisions of subsections (i) through (iv) above, moneys received by Energy Northwest as a result of any sale, lease, transfer or other disposition specified in such subsections and which are in excess of the amounts required for decommissioning and site restoration costs may be transferred to such funds or accounts determined by Energy Northwest or used to purchase or redeem Electric Revenue Bonds.

Insurance. Energy Northwest shall, to the extent available at reasonable cost with responsible insurers, keep, or cause to be kept, the works, plants and facilities comprising the properties of the related Project and the operation thereof insured, with policies payable to Energy Northwest for the benefit of Energy Northwest, the Participants and Bonneville, as their interests may appear, against risks of direct physical loss, damage to or destruction of such properties or any part thereof, and against accidents, casualties, or negligence, including liability insurance and employer's liability, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and such other insurance as may be agreed upon by the parties to the Columbia Project Agreement. To the extent such insurance is being maintained by Energy Northwest pursuant to the Prior Lien Resolutions, no such insurance need be maintained under the related Electric Revenue Bond Resolution. In the case of loss, including loss of revenue, caused by suspension or interruption of generation or transmission of power and energy by a Project, the proceeds of any insurance policy or policies covering such loss received by Energy Northwest, prior to the retirement of the related Prior Lien Bonds, shall be paid into the related Revenue Fund, and thereafter, shall be paid into the related General Revenue Fund. Within 60 days after the end of each fiscal year, Energy Northwest shall file, or cause to be filed, with the Trustee a certificate of an Engineer describing in reasonable detail the insurance on the Projects then in effect pursuant to the requirements of the related Electric Revenue Bond Resolution and stating whether, in its opinion, such insurance then in effect reasonably complies with the provisions hereof. Prior to the retirement of the Project 1, Columbia or Project 3 Prior Lien Bonds, the filing of such a certificate pursuant to the related Prior Lien Resolutions shall satisfy the requirement of the preceding sentence.

Books of Account; Annual Audit. Energy Northwest shall keep proper books of account for each Project, showing as a separate utility system the accounts of each Project in accordance with the rules and regulations prescribed by any governmental agency authorized to prescribe such rules, including the Division of Municipal Corporations of the State Auditor's office of the State of Washington, or other state department or agency succeeding to such duties of the State Auditor's office, and in accordance with the Uniform System of Accounts prescribed from time to time by the Federal Energy and Regulatory Commission, or any successor federal agency having jurisdiction over electric public utility companies owning and operating properties similar to each Project, whether or not Energy Northwest is required by law to use such system of accounts. Within 120 days after the end of each fiscal year, Energy Northwest shall cause such books of account to be audited by independent certified public accountants of national reputation licensed, registered or entitled to practice and practicing as such under the laws of the State of Washington who, or each of whom, is in fact independent and does not have any interest, direct or indirect, in any contract with Energy Northwest other than his contract of employment to audit books of account of Energy Northwest, and who is not connected with Energy Northwest as an officer or employee of Energy Northwest. A copy of each audit report, annual balance sheet and income and expense statement showing in reasonable detail the financial condition of each Project as of the close of each fiscal year and summarizing in reasonable detail the income and expenses for such year, including the transactions relating to the funds and accounts and the amounts expended for maintenance and for renewals, replacements and gross capital additions to each Project shall be filed promptly with the Trustee and sent to any Bondholder filing with Energy Northwest a written request for a copy thereof. Each such audit report shall state therein that the auditor has examined and is familiar with the provisions of the related Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution relating to the matters set forth above, and that as to such matters Energy Northwest is in compliance therewith or, if not in compliance therewith, the details of such failure to comply and the action to be taken by Energy Northwest to be in compliance therewith.

Consulting Engineer. So long as Energy Northwest owns and operates the Columbia Generating Station, Energy Northwest will retain on its staff one or more qualified engineers and hire an independent engineering firm when and as deemed necessary or advisable to provide immediate and continuous engineering counsel with respect to the Columbia Generating Station.

Protection of Security; Additional Parity Indebtedness. Energy Northwest is duly authorized under all applicable laws to create and issue the Electric Revenue Bonds and to adopt the Electric Revenue Bond Resolutions and to pledge the revenues and other moneys, securities and funds purported to be pledged by the Electric Revenue Bond Resolutions in the manner and to the extent provided in the Electric Revenue Bond Resolutions. The revenues and other moneys, securities and funds so pledged are and will be free and clear of any pledge, lien, charge or encumbrance thereon, or with respect thereto, prior to, or of equal rank with, the pledge created by the Electric Revenue Bond Resolutions, so long as any of the Project 1, Columbia or Project 3 Prior Lien Bonds remain outstanding, except for the lien and pledge of the Prior Lien Resolutions, and all corporate action on the part of Energy Northwest to that end has been duly and validly taken. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

Subject to the provisions of the Prior Lien Resolutions, Energy Northwest will not hereafter create any other special fund or funds for the payment of bonds, warrants or other obligations or issue any bonds, warrants or other obligations payable out of or secured by a pledge of revenues or create any additional obligations which will rank on a parity with or in priority over the pledge and lien of such revenues created under the Electric Revenue Bond Resolutions, except that Energy Northwest may issue bonds, notes or other obligations, under a separate resolution or resolutions, which are payable from or secured by a pledge of the revenues and may create or cause to be created any lien or charge on such revenues, ranking on a parity with the pledge and lien created by the Electric Revenue Bond Resolutions, for any one or more of the purposes provided in the Electric Revenue Bond Resolutions or may create Parity Reimbursement Obligations. However, Energy Northwest shall not issue any such additional bonds, notes or other obligations or create Parity Reimbursement Obligations unless, on the date of issue of such bonds, the certain contracts or agreements described in the Electric Revenue Bond Resolutions are in full force and effect and no Event of Default under the Electric Revenue Bond Resolutions shall have occurred and be continuing.

Further Assurances. Energy Northwest will at any and all times, insofar as it may be authorized so to do by law, pass, make, do, execute, acknowledge and deliver all and every such further resolutions, acts, deeds, conveyances, assignments, transfers and assurances as may be necessary or desirable for the better assuring, conveying, granting, assigning and confirming all and singular the rights, revenues and other funds pledged or assigned to the payment of the obligations issued by Energy Northwest payable from the revenues of each Project, including the Electric Revenue Bonds or intended so to be, or which Energy Northwest may hereafter become bound to pledge or assign.

Tax Covenants. Energy Northwest covenants with the owners from time to time of the Electric Revenue Bonds that (i) throughout the term of the Electric Revenue Bonds and (ii) through the date that the final rebate, if any, must be made to the United States in accordance with Section 148 of the Code it will comply with the provisions of Sections 103 and 141 through 150 of the Code and all regulations proposed and promulgated thereunder that must be satisfied in order that interest on the Electric Revenue Bonds shall be and continue to be excluded from gross income for federal income tax purposes.

Energy Northwest shall not permit at any time or times any of the proceeds of the Electric Revenue Bonds or any other funds of Energy Northwest to be used directly or indirectly to acquire any securities or obligations the acquisition of which would cause any Electric Revenue Bond to be an “arbitrage bond” as defined in Section 148 of the Code, or any successor provision of law.

Energy Northwest shall not permit at any time or times any proceeds of any Series of Electric Revenue Bonds or any other funds of Energy Northwest to be used, directly or indirectly, in a manner which would result in the exclusion of any Electric Revenue Bond from the treatment afforded by Section 103(a) of the Code.

Anything contained in the three preceding paragraphs to the contrary notwithstanding, Energy Northwest reserves the right to issue, from time to time, one or more Series of Electric Revenue Bonds the interest on which is includable in the gross income of the recipient thereof for federal income tax purposes ("Taxable Bonds"), provided that the issuance of any such Series of Taxable Bonds does not adversely affect the federal tax exemption of the interest on any other Series of Electric Revenue Bonds.

Events of Default and Remedies (Section 801)

The occurrence of one or more of the following events shall constitute an "Event of Default" under the Electric Revenue Bond Resolution to which such Event of Default relates:

(1) if payment of principal or the redemption price of any related Electric Revenue Bond shall not punctually be made when due and payable, whether at the stated maturity thereof, upon redemption or otherwise;

(2) if payment of the interest on any related Electric Revenue Bond shall not punctually be made when due;

(3) if payment of any related Parity Reimbursement Obligation shall not be punctually made when due;

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed (other than the covenant relating to compliance with the respective Prior Lien Resolutions), and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected; and provided further that the exclusion of the covenant relating to compliance with the respective Prior Lien Resolutions, shall not be construed to prevent the Trustee from enforcing any remedy it may have, at law or in equity, for a breach of such covenant;

(5) if an order, judgment, or decree shall be entered by any court of competent jurisdiction, with the consent or acquiescence of Energy Northwest, or if such order, judgment or decree, having been entered without the consent or acquiescence of Energy Northwest, shall not be vacated or set aside or discharged or stayed (or in case custody or control is assumed by said order, such custody or control shall not otherwise be terminated) within ninety (90) days after the entry thereof, and if appealed, shall not thereafter be vacated or discharged: (i) appointing a receiver, trustee or liquidator for Energy Northwest; or (ii) assuming custody or control of the whole or any substantial part of the applicable Project under the provisions of any law for the relief or aid of debtors; or (iii) approving a petition filed against Energy Northwest under the provisions of 11 USC 901-946, as amended (the "Bankruptcy Act"); or (iv) granting relief to Energy Northwest under any amendment to said Bankruptcy Act, or under any other applicable Bankruptcy Act, which shall give relief substantially similar to that afforded by Chapter IX thereof; and

(6) if Energy Northwest shall (i) admit in writing its inability to pay its debts generally as they become due; or (ii) file a petition in bankruptcy or seeking a composition of indebtedness; or (iii) make an assignment for the benefit of its creditors; or (iv) file a petition or any answer seeking relief under the Bankruptcy Act referred to in the preceding clause, or under any amendment thereto, or under any other applicable bankruptcy act which shall give relief substantially the same as that afforded by Chapter IX of said act; or (v) consent to the appointment of a receiver of the whole or any substantial part of the applicable Project; or (vi) consent to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of Energy Northwest or of the whole or any substantial part of the applicable Project.

Upon the occurrence of an Event of Default described in the preceding paragraphs, and in each and every such case, so long as such Event of Default shall not have been remedied, unless the principal of all the related Electric Revenue Bonds shall have already become due and payable, the Trustee may, and upon the written request of the owners of not less than 25% of all related Electric Revenue Bonds then outstanding shall, proceed to enforce by such proceedings at law or in equity as it deems most effectual the rights of related Bondholders, and either the Trustee (by notice in writing to Energy Northwest), or the owners of not less than 25% in principal amount of the related Electric Revenue Bonds outstanding (by notice in writing to Energy Northwest and the Trustee), may declare the principal of all the related Electric Revenue Bonds then outstanding, and the interest accrued thereon, to be due and payable immediately, and upon any such declaration the same shall become and be immediately due and payable; provided, however, that so long as any of the Prior Lien Bonds of the related Project remain outstanding, no such declaration may be made unless the principal of all the Prior Lien Bonds of the related Project then outstanding, and the interest accrued thereon, shall have been declared to be due and payable immediately pursuant to Section 12.1 of Resolution No. 769, Section 11.1 of Resolution No. 640 or Section 11.1 of Resolution No. 775, as the case may be. The Trustee shall not be obligated to notify Energy Northwest of its intent to make such a declaration prior to making such declaration. The right of the Trustee or of the owners of not less than 25% in principal amount of the related Electric Revenue Bonds to make any such declaration, however, shall be subject to the condition that if, at any time after such declaration, but before the related Electric Revenue Bonds shall have matured by their terms, all overdue installments of interest upon the related Electric Revenue Bonds, together with interest on such overdue installments of interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee (including reasonable fees and expenses of counsel to the Trustee), and all other sums then payable by Energy Northwest under the related Electric Revenue Bond Resolution (except the principal of, and interest accrued since the next preceding Payment Date on, the related Electric Revenue Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the related Electric Revenue Bonds or under the related Electric Revenue Bond Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be cured or provision shall be made therefor, then and in every such case the owners of a majority in principal amount of the related Electric Revenue Bonds outstanding, by written notice to Energy Northwest and to the Trustee, may rescind such declaration and annul such default in its entirety, or, if the Trustee shall have acted itself, and if there shall not have been theretofore delivered to the Trustee written directions to the contrary by the owners of a majority in principal amount of the related Electric Revenue Bonds then outstanding, then any such declaration shall *ipso facto* be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any resulting right or power.

Notice to Bondholders of an Event of Default (Section 802)

The Trustee, within 25 days after the occurrence of an Event of Default, shall give to the Bondholders of the related Electric Revenue Bonds, in the manner provided in the applicable Electric Revenue Bond Resolution, notice of all defaults known to the Trustee, and shall give prompt written notice thereof to Energy Northwest, unless such defaults shall have been cured before the giving of such notice.

Accounting and Examination of Records After Default (Section 803)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and account of Energy Northwest relating to the related Project and all other records relating thereto shall at all times be subject to the inspection and use of the Trustee and any persons holding at least 25% of the principal amount of the related Electric Revenue Bonds outstanding and of their respective agents and attorneys or of any committee therefor.

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, Energy Northwest will continue to account, as a trustee of an express trust, for all revenues and other moneys, securities and funds pledged under the related Electric Revenue Bond Resolution.

Application of Revenues in an Event of Default (Section 804)

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee (i) forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution, and (ii) subject to the provisions of the respective Prior Lien Resolutions as promptly as practicable after receipt thereof, all revenues of the related Project (provided that if other Parity Debt is outstanding Energy Northwest shall pay over to the Trustee the Trustee's pro rata share of such revenues).

Subject to the provisions of the Prior Lien Resolutions, respectively, during the continuance of an Event of Default, the revenues and other moneys of the related Project received by the Trustee shall be applied by the Trustee: first, to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the related Project, including the costs of decommissioning and site restoration, if any, and all other proper disbursements or liabilities made or incurred by the Trustee (including the fees and expenses of counsel to the Trustee); and second, to the then due and overdue payments into the related Debt Service Fund and the due and overdue payments on any related Parity Reimbursement Obligations and the due and overdue payments of any other obligation of Energy Northwest for which the Revenues are pledged on a parity with the pledge under Section 202(a) of the related Electric Revenue Bond Resolution pursuant to a Supplemental Electric Revenue Bond Resolution ("Other Parity Obligations"); and lastly, for any lawful purpose in connection with the related Project.

In the event that at any time the funds held by the Trustee shall be insufficient for the payment of the principal of, premium, if any, and interest then due on the related Electric Revenue Bonds and payments then due on any related Parity Reimbursement Obligations and Other Parity Obligations, such funds (other than funds held for the payment or redemption of particular Electric Revenue Bonds or Parity Reimbursement Obligations or Other Parity Obligations, including, without limiting the generality of the foregoing, amounts held in any Reserve Account for a particular Series of Electric Revenue Bonds) and all revenues of Energy Northwest and other moneys received or collected for the benefit or for the account of owners of the Electric Revenue Bonds and any Parity Reimbursement Obligations and Other Parity Obligations by the Trustee shall be applied as follows:

(1) Unless the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the applicable Project and all other proper disbursements or liabilities made or incurred by the Trustee;

Second, to the payment to the persons entitled thereto of all installments of interest then due on the related Electric Revenue Bonds (including any interest on overdue principal) in the order of the maturity of such installments, earliest maturities first, and on any related Parity Reimbursement Obligations and Other Parity Obligations and if the amounts available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Third, to the payment to the persons entitled thereto of the principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at the time of such payment without preference or priority of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, and if the amounts available therefor shall not be sufficient to pay in full any principal and premium, if any, due and unpaid upon the related Electric Revenue Bonds and on any related Parity Reimbursement Obligations and Other Parity Obligations at such time, then to the payment thereof, ratably, according to the amounts due respectively for principal and redemption premium, without any discrimination or preference.

(2) If the principal of all of the related Electric Revenue Bonds shall have become due and payable,

First, to the payment of all necessary and proper operating expenses of the related Project and all other proper disbursements or liabilities made or incurred by the Trustee; and

Second, to the payment of the principal and interest then due and unpaid upon the related Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any related Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation over any other Electric Revenue Bond or related Parity Reimbursement Obligation or Other Parity Obligation, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

Whenever moneys are to be applied as described in the preceding paragraphs, such moneys shall be applied by the Trustee, at such times, and from time to time, as it in its sole discretion shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future.

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its money, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

Remedies Not Exclusive (Section 809)

No remedy by the terms of either of the Electric Revenue Bond Resolutions conferred upon or reserved to the owners of the related Electric Revenue Bonds is intended to be exclusive of any other remedy, but each and every such remedy shall be cumulative and shall be in addition to any other remedy given to the owners of the related Electric Revenue Bonds or now or hereafter existing at law or in equity or by statute.

Waivers of Default (Section 810)

No delay or omission of any owner of Electric Revenue Bonds to exercise any right or power arising upon the occurrence of a default hereunder, including an Event of Default, will impair any right or power or shall be construed to be a waiver of any such default or to be an acquiescence therein. Every power and remedy given by this Article to the Trustee or to the owners of Electric Revenue Bonds may be exercised from time to time and as often as may be deemed expedient by such Trustee or by such owners.

Prior to the declaration of acceleration of the Electric Revenue Bonds as provided in Section 801, the holders of a majority in principal amount of the Electric Revenue Bonds at the time Outstanding, or their attorneys-in-fact duly authorized, may on behalf of the holders of all the Electric Revenue Bonds waive any past default under this Resolution and its consequences, except a default described in paragraph (1), (2), (3) or (4) of Section 801. No such waiver will extend to any subsequent or other default or impair any right consequent thereon.

Supplemental Electric Revenue Bond Resolutions (Article IX)

Supplemental Electric Revenue Bond Resolutions Effective Without Consent of Owners of Electric Revenue Bonds. Energy Northwest, from time to time and at any time and without the consent or concurrence of any owner of any Electric Revenue Bond, may adopt a resolution amendatory of each Electric Revenue Bond Resolution or supplemental to each Electric Revenue Bond Resolution (i) for the purpose of providing for the issuance of Electric Revenue Bonds pursuant to the provisions of Article II of each Electric Revenue Bond Resolution; or (ii) if the provisions of such Supplemental Electric Revenue Bond Resolutions shall not adversely affect the rights of the owners of the Electric Revenue Bonds of each Series or, if a Series consists of two or more subseries, of each subseries thereof, affected by such Supplemental Electric Revenue Bond Resolutions then outstanding, for any one or more of the following purposes:

(1) to make any changes or corrections in the Electric Revenue Bond Resolutions as to which Energy Northwest shall have been advised by counsel that the same are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provision or omission or mistake or manifest error contained in the Electric Revenue Bond Resolutions, or to insert in the Electric Revenue Bond Resolutions such provisions clarifying matters or questions arising under the Electric Revenue Bond Resolutions as are necessary or desirable;

(2) to add additional covenants and agreements of Energy Northwest for the purpose of further securing the payment of the Electric Revenue Bonds;

(3) to surrender any right, power or privilege reserved to or conferred upon Energy Northwest by the terms of the Electric Revenue Bond Resolutions;

(4) to confirm as further assurance any lien, pledge or charge, or the subjection to any lien, pledge, or charge, created or to be created by the provisions of the Electric Revenue Bond Resolutions;

(5) to grant or to confer upon the owners of the Electric Revenue Bonds any additional rights, remedies, powers, authority or security that lawfully may be granted to or conferred upon them, or to grant to or to confer upon the Trustee for the benefit of the owners of the Electric Revenue Bonds any additional rights, duties, remedies, powers, authority or security or to provide for one or more Credit Facilities;

(6) to make any appointment or to add any provision, in either case, required or permitted by the Electric Revenue Bond Resolutions to be so made or added pursuant to a Supplemental Electric Revenue Bond Resolution;

(7) to enter into Payment Agreements; and

(8) to make any other change which Energy Northwest deems necessary or desirable and which does not adversely affect the rights of the Bondholders.

Supplemental Electric Revenue Bond Resolutions Effective With Consent of Bondholders. At any time, Supplemental Electric Revenue Bond Resolutions may be adopted subject to consent by Bondholders in accordance with and subject to the provisions of each Electric Revenue Bond Resolution, which Supplemental Electric Revenue Bond Resolutions, upon the filing with the Trustee of a copy thereof certified by an authorized officer of Energy Northwest and upon compliance with the provisions of Article X of each Electric Revenue Bond Resolution, shall become fully effective in accordance with its terms as provided in said Article.

Powers of Amendment (Section 1002)

Any modification or amendment of the Electric Revenue Bond Resolutions or of the rights and obligations of Energy Northwest and of the owner of the Electric Revenue Bonds thereunder, in any particular, may be made by Supplemental Electric Revenue Bond Resolutions, with the written consent given as provided in each Electric Revenue Bond Resolution, (i) of the owners of not less than a majority in principal amount of the related Electric Revenue Bonds outstanding at the time such consent is given and (ii) in case less than all of the several Series of Electric Revenue Bonds or, if any Series consists of two or more subseries, the subseries thereof, then outstanding are affected by the modification or amendment, of the owners of not less than a majority in principal amount of the Electric Revenue Bonds of such Series or subseries, as the case may be, so affected and outstanding at the time such consent is given; except that if such modification or amendment will, by its terms, not take effect so long as any Electric Revenue Bonds of any specified like Series, subseries, if applicable, and maturity remain outstanding, the consent of the owners of such Electric Revenue Bonds shall not be required and such Electric Revenue Bonds shall not be deemed to be outstanding for the purpose of any calculation of outstanding Electric Revenue Bonds under this provision of each Electric Revenue Bond Resolution. No such modification or amendment shall permit a change in the terms of redemption or maturity of the principal of any outstanding Electric Revenue Bond or of any installment of interest thereon or a reduction in the principal amount or the redemption price thereof or in the rate of interest thereon without the consent of the owner of such Electric Revenue Bond, or shall reduce the percentages or otherwise affect the classes of Electric Revenue Bonds the consent of the owners of which is required to effect any such modification or amendment, or permit a preference or priority of any Electric Revenue Bond over any other or shall change or modify any of the rights or obligations of any fiduciary without its written assent thereto. For the purposes of this provision of each Electric Revenue Bond Resolution, a Series or subseries, as the case may be, shall be deemed to be affected by a modification or amendment of each Electric Revenue Bond Resolution if the same adversely affects or diminishes the rights of the owners of Electric Revenue Bonds of such Series or subseries, respectively. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment of the Electric Revenue Bonds of any particular Series, Subseries, if applicable, or maturity would be affected by any modification or amendment of the Electric Revenue Bond Resolutions and any such determination shall be binding and conclusive on Energy Northwest and all owners of Electric Revenue Bonds. For the purposes of this Section, the owners of the Electric Revenue Bonds may include the initial owners thereof, regardless of whether such Electric Revenue Bonds are being held for immediate resale.

Defeasance (Article XI)

Except as otherwise provided in each Supplemental Electric Revenue Bond Resolution authorizing the issuance of variable rate Electric Revenue Bonds, the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in such Electric Revenue Bond Resolutions, shall be fully discharged and satisfied as to any related Electric Revenue Bond and such related Electric Revenue Bond shall no longer be deemed to be outstanding hereunder,

(i) when such related Electric Revenue Bond shall have been canceled, or shall have been surrendered for cancellation or is subject to cancellation, or shall have been purchased by the Trustee from moneys held under the related Electric Revenue Bond Resolutions; or

(ii) as to any related Electric Revenue Bond not canceled or surrendered for cancellation or subject to cancellation or so purchased, when payment of the principal of and premium, if any, on such related Electric Revenue Bond, plus interest on such principal to the due date thereof (whether such due date be by reason of maturity or upon redemption or prepayment, or otherwise) either (A) shall have been made or caused to be made in accordance with the terms thereof, or (B) shall have been provided for by irrevocably depositing with the trustee or a paying agent for such Electric Revenue Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) moneys sufficient to make such payment or (2) Defeasance Obligations maturing, or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will insure the availability of sufficient moneys to make such payment, or a combination thereof, whichever Energy Northwest deems to be in its best interest, and all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to the Electric Revenue Bond with respect to which such deposit is made shall have been paid or the payment thereof provided for to the satisfaction of the Trustee and said paying agents. In addition, with respect to the Series 2006-B Taxable, the following provisions shall also be required for such Bonds to be deemed no longer outstanding under the respective Electric Revenue Bond Resolution: (1) Energy Northwest shall have delivered to the Trustee either (a) a ruling from the Internal Revenue Service to the effect that the Holders of such Bonds will not recognize income, gain or loss for federal income tax purposes as a result of Energy Northwest's exercise of its defeasance option and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such option had not been exercised, or (b) an opinion of counsel to the same effect as the ruling described in clause (a) of this paragraph; and (2) Energy Northwest has delivered an opinion of counsel stating that the deposit shall not result in Energy Northwest or the Trustee becoming or being deemed to be an "investment company" under the Investment Company Act of 1940.

At such time as an Electric Revenue Bond shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, such Electric Revenue Bond shall no longer be secured by or entitled to the benefits of the related Electric Revenue Bond Resolution, except for the purposes of any payment from such moneys or Defeasance Obligations.

Notwithstanding the foregoing, in the case of an Electric Revenue Bond which is to be redeemed or otherwise prepaid prior to its stated maturity, no deposit under clause (B) of subparagraph (ii) above shall constitute such payment, discharge and satisfaction as aforesaid until such Electric Revenue Bond shall have been irrevocably designated for redemption or prepayment and proper notice of such redemption or prepayment shall have been previously published in accordance with each Electric Revenue Bond Resolution or in accordance with the provisions of the Supplemental Electric Revenue Bond Resolutions which authorized the issuance of the Electric Revenue Bonds being refunded or provision satisfactory to the Trustee shall have been irrevocably made for the giving of such notice.

Any such moneys so deposited with the trustee or paying agents for the Electric Revenue Bonds as provided in the Electric Revenue Bond Resolutions may at the direction of Energy Northwest also be invested and reinvested in Defeasance Obligations, maturing in the amounts and times as hereinbefore set forth. All income from all Defeasance Obligations in the hands of the trustee or paying agents which is not required for the payment of the Electric Revenue Bonds and interest and premium thereon with respect to which such moneys shall have been so deposited, shall be paid to Energy Northwest for deposit in the respective General Revenue Funds. Likewise, whenever all of the Electric Revenue Bonds of a Series shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, as aforesaid, the amounts, if any, remaining on deposit to the credit of the Reserve Accounts established for such Series shall be paid to Energy Northwest for deposit in the respective General Revenue Funds.

Any provision contained in the Electric Revenue Bond Resolutions to the contrary notwithstanding, all moneys and Defeasance Obligations set aside and held in trust for the payment of Electric Revenue Bonds shall be applied to and used solely for the payment of the particular Electric Revenue Bond with respect to which such moneys and Defeasance Obligations have been so set aside in trust.

Notwithstanding anything in the Electric Revenue Bond Resolutions to the contrary, if moneys or Defeasance Obligations have been deposited or set aside with the trustee or a paying agent for the payment of a specific Electric Revenue Bond and such Electric Revenue Bond shall be deemed to have been paid and to be no longer outstanding, but such Electric Revenue Bond shall not have in fact been actually paid in full, no amendment to the provisions of either of the Electric Revenue Bond Resolutions shall be made without the consent of the owner of each Electric Revenue Bond affected thereby.

Energy Northwest may at any time surrender to the Trustee for cancellation by it any Electric Revenue Bonds previously executed and delivered, which Energy Northwest may have acquired in any manner whatsoever, and such Electric Revenue Bonds upon such surrender for cancellation shall be deemed to be paid and no longer outstanding under either of the Electric Revenue Bond Resolutions.

Neither the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions, nor any Supplemental Resolutions authorizing Parity Reimbursement Obligations and/or Other Parity Obligations, shall be discharged or satisfied with respect to such Parity Reimbursement Obligations or Other Parity Obligations, respectively, until such Parity Reimbursement Obligations shall have been paid in accordance with their terms.

Summary of the Supplemental Electric Revenue Bond Resolutions

Debt Service Account. Each Supplemental Electric Revenue Bond Resolution creates and establishes a special trust account of the Debt Service Fund which shall be held by the Trustee subject to the lien of the related Project's Electric Revenue Bond Resolution. The Debt Service Accounts shall be funded as provided in the related Electric Revenue Bond Resolution and amounts therein shall be used and applied as provided in the related Supplemental Electric Revenue Bond Resolution and in the related Electric Revenue Bond Resolution.

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SUMMARY OF CERTAIN PROVISIONS OF PRIOR LIEN RESOLUTIONS

The following summary is a brief outline of certain provisions contained in the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution as amended and supplemented (collectively referred to in this Appendix H-2 as the "Prior Lien Resolutions"), and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Prior Lien Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the respective Bond Fund Trustees and Paying Agents for the Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds and Project 3 Prior Lien Bonds (together, the "Prior Lien Bonds").

Subsequent Series of Prior Lien Bonds

Under the Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, Energy Northwest has covenanted with the owners from time to time of the Electric Revenue Bonds not to issue any further Prior Lien Bonds or any other bonds, warrants or obligations having a lien on Revenues on a parity with the Prior Lien Bonds.

Construction Fund

The Project 1 Prior Lien Resolution establishes an Energy Northwest Project No. 1 Construction Fund and a Construction Interest Account and a Fuel Account therein, to be held by the Construction Fund Trustee. U.S. Bank National Association is Construction Fund Trustee under the Project 1 Prior Lien Resolution.

The Project 3 Prior Lien Resolution establishes an Energy Northwest Nuclear Project No. 3 Construction Fund to be held in trust by Energy Northwest.

The Project 3 Prior Lien Resolution provides that if working capital is not provided for by September 1, 1982, or if a Reserve and Contingency Fund requirement of $3,000,000 is not provided for by the Date of Commercial Operation, through revenues received pursuant to the Project 3 Net Billing Agreements, such amounts will be provided from Project 3 Prior Lien Bond proceeds, including moneys then on deposit in the Project No. 3 Construction Fund.

The proceeds of sale of subsequent Series of Project 1 or Project 3 Prior Lien Bonds issued to pay the Cost of Construction of the related Net Billed Project will be applied as follows:

(a) An amount equal to the interest accrued on such Series of Prior Lien Bonds from their date to the date of their delivery to the initial purchasers will be credited, in the case of Project 1 Prior Lien Bonds, to the interest Account in the Construction Fund for Project 1 or, in the case of Project 3 Prior Lien Bonds, to the Interest Account in the Bond Fund for Project 3;

(b) Except as otherwise authorized pursuant to the amendments described under "Effect of Amendments Adopted September 4, 1989 and March 15, 1990 (Project 1, Columbia and Project 3)" above, an amount equal to the largest amount of interest required to be paid on such Series of Prior Lien Bonds during any six-month period from the date of such Bonds to the final maturity date thereof will be credited to the Reserve Account in the Bond Fund for the related Net Billed Project if such amount is not funded by revenues of the related Net Billed Project;

(c) In the case of Project 1 Prior Lien Bonds, such amounts as Energy Northwest determines will be credited to the Fuel Account in the Construction Fund for Project 1; and

(d) The balance of such Bond proceeds will be deposited in the Construction Fund for the respective Net Billed Project, provided a part of such proceeds may be deposited in the Revenue Fund for such Net Billed Project as required for additional working capital.

Moneys in each Net Billed Project Construction Fund are to be used to pay Energy Northwest's Cost of Construction of such Net Billed Project, which includes costs of constructing and acquiring such Project, obtaining permits and licenses and acquiring property and fuel, trustees' and paying agents' fees, taxes and insurance premiums, the cost of engineering services and administrative and overhead expenses of Energy Northwest allocable to the acquisition and construction of such Project. The cost of acquiring fuel for each Net Billed Project will be paid from such Project's Fuel Fund.

Each Prior Lien Resolution prescribes certain procedures designed to safeguard payments or transfers from each Net Billed Project's Construction Fund, including, among others, certificates by the appropriate Construction Engineer and, for Project 1, a detailed itemization by Energy Northwest of the amounts to be paid and the purposes thereof.

Moneys remaining in a Net Billed Project Construction Fund after providing for the payment of all Costs of Construction, in the case of Project 1, and all of Energy Northwest's Costs of Construction, in the case of Project 3, and after required payments, if any, to other accounts, are to be transferred to such Project's Bond Retirement Account.

Other Funds Established by the Prior Lien Resolutions; Flow of Revenues

In addition to the Construction Fund, each Prior Lien Resolution establishes a separate Revenue Fund, Fuel Fund, and Reserve and Contingency Fund. Each Prior Lien Resolution also establishes a Bond Fund (including an Interest Account, a

Principal Account, a Bond Retirement Account, and a Reserve Account) from which payments are to be made with respect to the related Prior Lien Bonds issued to pay the Cost of Construction of the related Net Billed Project. A separate bond fund, including an interest account, a principal account (if applicable), a bond retirement account (if applicable), and a reserve account, is required to be established for each Series of additional Prior Lien Bonds issued for purposes other than paying the Cost of Construction of the related Net Billed Project. All such funds are to be held by Energy Northwest, except for the Project No. 1 Construction Fund, the Project No. 1 Bond Fund, the Columbia Bond Fund, the Project No. 3 Bond Fund and the separate bond funds (collectively, the "Bond Funds"), each of which is to be held by the appropriate Bond Fund Trustee.

Project No. 1 Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Project 1 are to be paid into the Project No. 1 Revenue Fund. Moneys in such Revenue Fund are to be used solely for the purpose of making required payments into the Hanford Project Revenue Fund, paying the principal of and premium, if any, and interest on the Project 1 Prior Lien Bonds, paying for the costs of operating and maintaining Project 1, making required payments into the Project No. 1 Fuel Fund and Reserve and Contingency Fund, making repairs, renewals, replacements, additions, betterments and improvements to and extensions of Project 1, and paying all other charges or obligations against the revenues pledged to the Project No. 1 Revenue Fund.

Project No. 1 Bond Funds: From the revenues theretofor paid into the Project No. 1 Revenue Fund, Energy Northwest is to pay monthly into the Project No. 1 Bond Funds, after making the required payments, if any, to the Hanford Project Revenue Fund, fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on the Project 1 Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Project No. 1 Reserve Account, for each Series of outstanding Project 1 Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Project 1 Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six-month period from the date of such Bonds to the final maturity date thereof. Energy Northwest is required to maintain the required amount in the reserve accounts by payments from the Project No. 1 Revenue Fund. *Project No. 1 Fuel Fund:* Beginning on the Date of Commercial Operation, all payments for fuel for Project 1 will be made from the Project No. 1 Fuel Fund. After the Date of Commercial Operation, after making the required payments, if any, into the Hanford Project Revenue Fund and Project No. 1 Bond Funds and after paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Project 1, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Project No. 1 Revenue Fund to said Fuel Fund the following amounts:

(i) the amount included in the annual budget for fuel adopted pursuant to the Project 1 Project Agreement,

(ii) all amounts received by Energy Northwest as fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(iii) any additional amounts necessary to avoid a deficiency in the Project No. 1 Fuel Fund.

Upon termination of Project 1 in accordance with the Project 1 Project Agreement, the Project 1 Prior Lien Resolution required that the unobligated balance in the Project No. 1 Fuel Fund be transferred into the Project No. 1 Revenue Fund.

Project No. 1 Reserve and Contingency Fund: Since September 25, 1980, Energy Northwest has been required to pay monthly out of the Project No. 1 Revenue Fund into the Project No. 1 Reserve and Contingency Fund, after making the required payments, if any, into the Hanford Project Revenue Fund and the Project No. 1 Bond Funds, paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Project 1, including taxes or payments in lieu thereof, and making the required payments in the Project No. 1 Fuel Fund, an amount equal to 10% of the aggregate of the amounts required to be paid during such month into the Interest, Principal and Bond Retirement Accounts in the Project No. 1 Bond Funds.

Moneys in the Reserve and Contingency Fund shall be used from time to time to make up any deficiencies in the Interest Account, Principal Account or Bond Retirement Account in the Bond Fund for which funds are not available in the Construction Fund or the Reserve Account, or to make up any deficiencies in the interest account, principal account or bond retirement account in any bond fund established for additional Bonds issued pursuant to the Project 1 Prior Lien Resolution for which funds are not available in any construction fund or reserve account for such additional Bonds, and any such moneys in the Reserve and Contingency Fund are hereby pledged as additional payments into the Bond Fund or any such bond fund to the extent required to make up any such deficiencies. To the extent not required for any such deficiency, moneys in the Reserve and Contingency Fund may be applied on and after the Date of Commercial Operation to any one or more of the following:

(1) to pay the cost of renewals and replacements to Project 1;

(2) to pay the cost of normal additions to and to extensions of Project 1; and

(3) to pay extraordinary operation and maintenance costs, including extraordinary costs of Fuel and the cost of preventing or correcting any unusual loss or damage (including major repairs) to Project 1.

If, as of June 30 in any year, moneys and value of Investment Securities in the Reserve and Contingency Fund shall exceed the amount of the then commitments or obligations incurred by the then requirements of Energy Northwest for any of the foregoing purposes, plus $3,000,000, the amount of such excess shall be paid into the Reserve Account and the reserve account for any series of additional Bonds issued pursuant to the Project 1 Prior Lien Resolution to the extent of any deficiency therein (pro rata in proportion to the respective deficiencies if such excess is insufficient to satisfy all such deficiencies) and the balance, if any, of such excess shall be paid as of June 30 into the Revenue Fund.

Columbia Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Columbia are to be paid into the Columbia Revenue Fund. Moneys in the Columbia Revenue Fund are to be used for the purpose of making required payments into the Columbia Bond Funds, paying for the costs of operating and maintaining Columbia, making required payments into the Columbia Fuel Fund and the Columbia Reserve and Contingency Fund, paying the costs of repairs, renewals, replacements, additions, betterments and improvements to and extensions of Columbia, and paying all other charges or obligations against the revenues pledged to the Columbia Revenue Fund.

Columbia Bond Funds: From the revenues theretofore paid into said Revenue Fund, Energy Northwest is to pay monthly into the Columbia Bond Funds fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on Columbia Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Columbia Reserve Account, for each Series of outstanding Columbia Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Columbia Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six-month period from the date of such Bonds to the final maturity date thereof. The reserve account requirement for additional Columbia Prior Lien Bonds shall be deposited from Columbia Prior Lien Bond proceeds or revenues available therefor at the time of issuance of such Bonds. Energy Northwest is required to maintain the required amount in said reserve accounts by payments from the Columbia Revenue Fund.

Columbia Fuel Fund: All payments for fuel for Columbia have been made, since the Date of Commercial Operation of Columbia, and will continue to be made, from the Columbia Fuel Fund. After making the required payments into the Columbia Bond Funds and after paying or making provision for payment of the reasonable and necessary costs of operating and maintaining Columbia, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Columbia Revenue Fund to said Fuel Fund the following amounts:

(1) the amount included in the annual budget for fuel adopted pursuant to the Columbia Net Billing Agreement,

(2) all amounts received by Energy Northwest from fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(3) any additional amounts necessary to avoid a deficiency in said Fuel Fund.

If Columbia is terminated pursuant to the Columbia Project Agreement, the Columbia Prior Lien Resolution requires that the balance in the Columbia Fuel Fund be transferred into the Columbia Revenue Fund.

Columbia Reserve and Contingency Fund: Since September 25, 1977, Energy Northwest has been required to pay monthly out of the Columbia Revenue Fund into the Columbia Reserve and Contingency Fund, after making the required payments into the Columbia Bond Funds, paying or making provisions for payment of the reasonable and necessary costs of operating and maintaining Columbia, and making the required payments into the Columbia Fuel Fund, an amount equal to 10% of the aggregate of the amounts required to be paid during such month from said Revenue Fund into the Interest, Principal, and Bond Retirement Accounts in the Columbia Bond Funds.

Project No. 3 Revenue Fund: All income, revenues, receipts, and profits derived by Energy Northwest from its ownership and operation of Project 3 are to be paid into the Project No. 3 Revenue Fund. Moneys in the Project No. 3 Revenue Fund are to be used for the purpose of making required payments into the Project No. 3 Bond Funds, paying for Energy Northwest's costs of operating and maintaining Project 3, making required payments into the Project No. 3 Fuel Fund and the Project No. 3 Reserve and Contingency Fund, paying Energy Northwest's costs of repairs, renewals, replacements, additions, betterments and improvements to and extensions of Project 3, and paying all other charges or obligations against the revenues pledged to the Project No. 3 Revenue Fund.

Project No. 3 Bond Funds: From the revenues theretofore paid into said Revenue Fund, Energy Northwest is to pay monthly into the Project No. 3 Bond Funds fixed amounts sufficient in the aggregate to pay the principal of and premium, if any, and interest on the Project 3 Prior Lien Bonds as the same become due and payable.

There is required to be paid into and maintained in the Project No. 3 Reserve Account, for each Series of outstanding Project 3 Prior Lien Bonds issued to pay costs of construction, and in separate reserve accounts, for each Series of outstanding Project 3 Prior Lien Bonds issued for other purposes, an amount equal to the largest amount of interest on such Bonds during any six month period from the date of such Bonds to the final maturity date thereof. Energy Northwest is required to maintain the required amount in the reserve accounts by payments from the Project No. 3 Revenue Fund.

Project No. 3 Fuel Fund: Beginning on the Date of Commercial Operation, all payments for fuel for Project No. 3 will be made from the Project No. 3 Fuel Fund. After the Date of Commercial Operation, after making the required payments into the Project No. 3 Bond Funds and after paying or making provision for payment of Energy Northwest's reasonable and necessary costs of operating and maintaining Project 3, including taxes or payments in lieu thereof, Energy Northwest will transfer from the Project No. 3 Revenue Fund to said Fuel Fund the following amounts:

(1) the amount included in the annual budget for fuel adopted pursuant to the Project 3 Project Agreement,

(2) all amounts received by Energy Northwest from fuel credits, including the proceeds of the sale of fuel creditable to operations, and

(3) any additional amounts necessary to avoid a deficiency in said Fuel Fund.

Upon termination of Project 3 pursuant to the Project 3 Project Agreement, the Project 3 Prior Lien Resolution required that the unobligated balance in the Project No. 3 Fuel Fund be transferred into the Project No. 3 Revenue Fund.

Project No. 3 Reserve and Contingency Fund: Since September 25, 1982, Energy Northwest has been required to pay monthly out of the Project No. 3 Revenue Fund into the Project No. 3 Reserve and Contingency Fund, after making the required payments into the Project No. 3 Bond Funds, paying or making provision for payment of Energy Northwest's reasonable and necessary costs of operating and maintaining Project 3, and making the required payments into the Project No. 3 Fuel Fund, an amount equal to 10% of the aggregate of the amounts required to be paid during such month from said Revenue Fund into the Interest, Principal and Bond Retirement Accounts in the Project No. 3 Bond Funds.

Moneys in each Net Billed Project's Reserve and Contingency Fund are required to be used to make up deficiencies in the respective Project's Bond Funds for which funds are not available in the respective Project's Construction Fund or Reserve Accounts. To the extent not required for any such deficiency, moneys in each Project's Reserve and Contingency Fund may be used after the respective Date of Commercial Operation for any one or more of the following purposes:

(i) To pay the cost of renewals, replacements and normal additions to and extensions of such Net Billed Project; and

(ii) To pay extraordinary operation and maintenance costs, including extraordinary costs of fuel and the cost of preventing or correcting any unusual loss or damage (including major repairs) to such Project.

Resolution No. 565 and Resolution No. 566, each adopted by the Executive Board of Energy Northwest on December 7, 1989, and the Columbia 1990A Supplemental Resolution provide that, unless Financial Guaranty Insurance Company consents to the deposit of a Financial Guaranty in a reserve account, certain requirements must be met as a condition to any such deposit.

Amounts on deposit in the Interest Account representing interest accrued on refunded Project 1, Columbia or Project 3 Prior Lien Bonds (as the case may be) no longer deemed outstanding under the applicable Prior Lien Resolution may be withdrawn on the date such refunded Bonds cease to be outstanding and may be transferred to a separate trust fund established with the applicable Bond Fund Trustee or Paying Agent to pay when due interest on such refunded Bonds.

The applicable Bond Fund Trustee shall, after making the required transfers of investment income to the applicable Revenue Fund, transfer the balance remaining on deposit in the applicable Interest Account, Principal Account, Bond Retirement Account and the Reserve Account, as directed by Energy Northwest, to the trustee of the applicable trust fund established to pay the principal of, and redemption premium, if any, and interest on the related Prior Lien Bonds, for deposit into such separate trust fund or, to the extent not so transferred, to the applicable bond fund trustee of each bond fund established for bonds, pursuant to the applicable Prior Lien Resolution and then outstanding, for deposit to the credit of the interest account therein in the same proportion as the amount of interest due on the next succeeding interest payment date of such series of Prior Lien Bonds bears to the total amount of interest due on such next succeeding interest payment date on all such series of bonds.

Investment of Funds: The term "Investment Securities," as defined in the Project 1 Prior Lien Resolution, the Columbia Prior Lien Resolution and the Project 3 Prior Lien Resolution, means (i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America; (ii) general obligation bonds of any state of the United States rated by a nationally recognized bond rating agency in either of the two highest rating categories assigned by such rating agency; (iii) bonds, debentures, notes or participation certificates issued by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-Import Bank of the United States, Federal Land Banks or the Federal National Mortgage Association or of any agency of or corporation wholly owned by the United States of America; (iv) in the case of the Project 1 Prior Lien Resolution and the Columbia Prior Lien Resolution, Public Housing Bonds or Project Notes issued by Public Housing Authorities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof and, in the case of the Project 3 Prior Lien Resolution, New Housing Authority Bonds or Project Notes issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof; (v) bank time deposits evidenced by certificates of deposit, and, in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, by bankers' acceptances, in each case, issued by any bank, trust company or national banking association authorized to do business in the State of Washington, which is a member of the Federal Reserve System, provided that the aggregate of such bank time deposits and, in the case of the Project 1 or Project 3 Prior Lien Resolution, bankers' acceptances issued by any bank, trust company or banking association do not exceed at any time, in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, fifty per centum (50%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and, in the case of the Columbia Prior Lien Resolution, twenty-five per centum (25%) of the total of the capital stock and surplus of such bank, trust company or banking association; (vi) in the case of the Project 1 Prior Lien Resolution and the Project 3 Prior Lien Resolution, bank time deposits evidenced by certificates of deposit, and bankers' acceptances, issued by any bank, trust company or national banking association authorized to do business in any state of the United States of America other than the State of Washington, which is a member of the Federal Reserve System, provided that the aggregate of such bank time deposits and bankers' acceptances issued by any bank, trust company or banking association do not exceed at any one time twenty-five per centum (25%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and provided further that such capital stock, surplus and undivided profits shall not be less than Fifty Million Dollars ($50,000,000); and (vii) in the case of the Project 1 Prior Lien Resolution, evidences of indebtedness issued by any corporation organized and existing under the laws of any state of the United States of America rated by any nationally recognized bond rating agency in either of the two highest rating categories assigned by such rating agency.

Moneys in the Project No. 1 Revenue Fund not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at or prior to the estimated time for disbursement of such moneys. Moneys in the Project No. 1 Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Project No. 1 Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 1 Prior Lien Bonds). Moneys in the Project No. 1 Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 1 Prior Lien Bonds). Moneys in the Project No. 1 Construction Fund are to be invested by the Project No. 1 Construction Fund Trustee in Investment Securities maturing or redeemable within five years of the date of investment.

Moneys in the Columbia Revenue Fund not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at or prior to the estimated time for the disbursement of such moneys. Moneys in the Columbia Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Columbia Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Columbia Prior Lien Bonds). Moneys in the Columbia Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within two years from the date of investment with respect to the Fuel Fund and within seven years from the date of investment with respect to the Reserve and Contingency Fund (but in each case maturing prior to the final maturity date of the Columbia Prior Lien Bonds).

Moneys in the Project No. 3 Revenue Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable at or prior to the estimated time for the disbursement of such moneys. Moneys in the Project No. 3 Interest Accounts, Principal Accounts and Bond Retirement Accounts are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable on or before the respective dates when such moneys will be required for the purposes intended. Except as otherwise described below, moneys in the Project No. 3 Reserve Accounts not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 3 Prior Lien Bonds). Moneys in the Project No. 3 Fuel Fund and Reserve and Contingency Fund not required for immediate disbursement are to be invested in Investment Securities maturing or redeemable within seven years from the date of investment (but maturing prior to the final maturity date of the Project 3 Prior Lien Bonds). Moneys in the Project No. 3 Construction Fund are to be invested in Investment Securities maturing or redeemable within seven years of the date of investment.

In the case of certain Refunding Bonds, the supplemental resolutions authorizing such Refunding Bonds provide that moneys on deposit in the related Project's reserve account in the bond fund established for such Refunding Bonds and not required for immediate disbursement are to be invested in Investment Securities described in clauses (i) through (iv) above maturing or redeemable at the option of the holder thereof on or prior to the final maturity date of such Refunding Bonds.

Excess Moneys: Moneys and the value of Investment Securities in each Project's Reserve and Contingency Fund in excess of $3,000,000 plus the commitments or obligations incurred by, or the requirements of Energy Northwest for, any of the purposes for which such Reserve and Contingency Funds may be used constitute "excess moneys" in respect of such Fund; and moneys and the value of Investment Securities described in clauses (i) through (iv) in this Appendix H-2 under "Investment of Funds" in each Project's Reserve Accounts in excess of the amounts required to be maintained in said Reserve Accounts constitute "excess moneys" in respect of such Accounts.

If as of any June 30, excess moneys exist in the Reserve and Contingency Fund for any Net Billed Project, such moneys shall be paid proportionately into such Project's Reserve Accounts, to the extent of any deficiency therein, and the balance of such excess moneys shall be paid into such Project's Revenue Fund.

If as of any June 30, excess moneys exist in the Reserve Account in the Bond Fund for any Net Billed Project, such moneys shall be paid proportionately into such Project's other reserve accounts in the separate bond funds, to the extent of any deficiency therein, and the balance of such excess moneys shall be paid into such Project's Revenue Fund.

If as of June 30, there shall exist in any Net Billed Project's Revenue Fund, after giving effect to any transfer of excess moneys from such Project's Reserve Account and Reserve and Contingency Fund to such Fund, an amount which exceeds Energy Northwest's required amount of working capital for such Project, the amount of such excess is to be applied to reduce annual power costs under the related Net Billing Agreements. The "required amount of working capital" shall be $3,000,000 or, in the case of the Project 1 and 3 Prior Lien Resolutions, such greater amount, and, in the case of the Columbia Prior Lien Resolution, such lesser amount (but not less than $2,000,000) or such greater amount, as may be decided upon by Energy Northwest and Bonneville with the approval of the Consulting Engineer. In addition, if Energy Northwest and Bonneville agree, all or any part of such excess over required working capital for a Net Billed Project may be applied to the making of repairs, renewals, replacements, additions, betterments and improvements to, and extensions of, such Project, the purchase or redemption of Bonds for such Project or for other purposes in connection with such Project.

Certain Covenants

Certain covenants of Energy Northwest with the holders of the Prior Lien Bonds are summarized as follows:

The Hanford Project: Under the Project 1 Prior Lien Resolution, Energy Northwest covenants that it (a) will not issue any evidences of indebtedness under Resolution No. 178 so long as the obligations of said resolution are satisfied under the Project 1 Prior Lien Resolution, (b) will discharge all of its duties and obligations under Resolution No. 178, (c) will make all payments and deposits to be made under the provisions of Resolution No. 178 from moneys to be provided pursuant to the Project 1 Prior Lien Resolution if and to the extent such obligations are not otherwise provided for, (d) will, on each December 31, apply any excess of amounts in the Hanford Project Revenue Fund over the required amount of working capital to reduce the amounts required by the Project 1 Prior Lien Resolution to be deposited in the Hanford Project Revenue Fund, and (e) will not amend Resolution No. 178 in any manner which adversely affects the rights of Bondholders under the Project 1 Prior Lien Resolution.

The Net Billed Projects: Energy Northwest covenants that it will, subject to the Project Agreements for each of the Net Billed Projects, complete construction of the Net Billed Projects at the earliest practicable time, operate such Projects and the business in connection therewith in an efficient manner and at reasonable cost, maintain such Projects in good condition and make all necessary and proper repairs, renewals, replacements, additions, extensions and betterments to such Projects.

Rates: Energy Northwest covenants that it will dispose of all capability of and power and energy from Project 1 solely for the benefit and account of such Project and pursuant to the provisions of the Project 1 Net Billing Agreements; and Energy Northwest covenants that it will maintain and collect rates and charges for capability, power and energy and other services, facilities and commodities sold, furnished or supplied through such Project, which will be adequate, whether or not the generation or transmission of power by such Project is suspended, interrupted or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to make the required payments into the Hanford Project Revenue Fund, (ii) to pay the expenses of operating and maintaining Project 1, (iii) to make the required payments into the Project No. 1 Bond Funds and (iv) to make the payments required into certain funds under the Project 1 Prior Lien Resolution.

Energy Northwest covenants that it will dispose of all capability of and power and energy from Columbia solely for the benefit and account of such Project and pursuant to the provisions of the Columbia Net Billing Agreements; and Energy Northwest covenants that it will maintain and collect rates and charges for power and energy, including capability, and other services, facilities, and commodities sold, furnished, or supplied through such Project, which will be adequate, whether or not the generation or transmission of power by the Project is suspended, interrupted, or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to pay the expenses of operating, maintaining and repairing such Project, (ii) to make the required payments into the Columbia Bond Funds, and (iii) to make the payments required into certain funds under the Columbia Prior Lien Resolution.

Energy Northwest covenants that it will dispose of all capability of and power and energy from Project 3 solely for the benefit and account of such Project and pursuant to the provisions of the Project 3 Net Billing Agreements and the Project 3 Power Sales Agreement; and Energy Northwest covenants that it will maintain and collect rates and charges for power and energy, including capability, and other services, facilities and commodities sold, furnished or supplied by such Project, which will be adequate, whether or not the generation or transmission of power by the Project is suspended, interrupted or reduced for any reason whatever, to provide revenues sufficient, among other things, (i) to pay Energy Northwest's expenses of operating and maintaining such Project, (ii) to make the required payments into the Project No. 3 Bond Funds, and (iii) to make the required into certain funds under the Project 3 Prior Lien Resolution.

Net Billing Agreements and Project Agreements: Energy Northwest covenants that it will not voluntarily consent to any amendment or permit any rescission of or take any action under or in connection with any of the Project Agreements or the Net Billing Agreements which will in any manner impair or adversely affect the rights of Energy Northwest or any of its Bondholders, or take any action under or in connection with the Net Billing Agreements which will reduce the payments provided for therein.

Disposition of Properties: Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Project 1 except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Hanford Project Revenue Fund and the Project No. 1 Bond Funds sufficient to retire all of the Project 1 Prior Lien Bonds and the Hanford Project Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Project 1 and any real or personal property comprising a part thereof which is unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Project 1, in which case $100,000 of the moneys received therefor is to be transferred to the Project No. 1 Reserve and Contingency Fund and the balance is to be paid proportionately into the Project No. 1 Bond Retirement Accounts unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Project No. 1 Reserve and Contingency Fund or the Project No. 1 Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys received therefor are to be paid proportionately into the Project No. 1 Bond Retirement Accounts.

Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Columbia except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Columbia Bond Funds sufficient to retire all of the Columbia Prior Lien Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Columbia and any real or personal property comprising a part thereof which a Consulting Engineer has certified that such properties are not unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Columbia, in which case $50,000 of the moneys received therefor is to be transferred to the Columbia Reserve and Contingency Fund and the balance is to be paid proportionately into the Columbia Bond Retirement Accounts unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Columbia Reserve and Contingency Fund or the Columbia Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys received therefor are to be paid proportionately into the Columbia Bond Retirement Accounts.

Energy Northwest covenants that it will not sell, mortgage, lease or otherwise dispose of any properties of Project 3 except that (a) Energy Northwest may sell, lease or otherwise dispose of such properties if simultaneous provision is made for the payment of cash into the Project No. 3 Bond Funds sufficient to retire all of the Project 3 Prior Lien Bonds and to pay interest accrued thereon or (b) Energy Northwest may sell, lease or otherwise dispose of any portion of the works, plants, and facilities of Project 3 and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete or no longer required for use in connection with the operation of Project 3, in which case $100,000 of the moneys received therefor is to be transferred to the Project No. 3 Reserve and Contingency Fund and the balance is to be paid proportionately into the Project No. 3 Bond Retirement Accounts, unless such disposition is in connection with the replacement of such properties or the disposition of fuel, in which case all moneys received from such disposition are to be transferred to the Project No. 3 Reserve and Contingency Fund or the Project No. 3 Fuel Fund, respectively, or (c) in the event that the ownership of such properties in whole or in part is transferred by operation of law, moneys, received therefor are to be paid proportionately into the Project No. 3 Bond Retirement Accounts.

In the case of Project 1 and Project 3, notwithstanding the provisions of clauses (b) and (c) above with respect to said Project, moneys received by Energy Northwest prior to the Date of Commercial Operation for a Net Billed Project as a result of any sale, lease, transfer or other disposition specified therein shall be transferred to such Project's Construction Fund.

In exercising any rights it may have to redeem such Bonds at par under the extraordinary redemption provisions relating to such Bonds in the event of a termination of the related Project, it will only redeem such Bonds from the proceeds, if any, received by Energy Northwest from the sale or other disposition of Project 1, Columbia or Project 3 properties, as the case may be, and, in the case of the Project 1 and Project 3 Prior Lien Bonds, from amounts, if any, then on deposit in the Construction Fund established under the Project 1 Prior Lien Resolution or the Project 3 Prior Lien Resolution, as the case may be.

Insurance: Energy Northwest covenants that it will keep Project 1, Columbia and Project 3 insured, to the extent such insurance is available at reasonable cost, against risks of direct physical loss or damage to or destruction of each such Project, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and against accidents, casualties, or negligence, including liability insurance and employer's liability, in the case of Project 1 and Project 3, at least to the extent that similar insurance is usually carried by electric utilities operating like properties.

In the event that any loss or damage to the properties of any Net Billed Project occurs during the period of construction of such Project, Energy Northwest is to transfer the insurance proceeds, if any, in respect of such loss or damage to such Project's Construction Fund; any insurance proceeds received by Energy Northwest in respect of such loss or damage occurring thereafter are to be transferred into such Project's Reserve and Contingency Fund, or, in the case of insurance covering loss or damage to fuel, to such Project's Fuel Fund.

Books of Account: Energy Northwest covenants that it will keep proper books of account, showing Project 1, Columbia and Project 3 as separate utility systems in accordance with the rules and regulations of the Division of Municipal Corporations of the State Auditor's office of the State of Washington and in accordance with the Uniform System of Accounts prescribed by the Federal Power Commission. Such books of account are to be audited annually by a firm of independent certified public accountants of national reputation. Bondholders may obtain copies of the annual financial statements showing the financial condition of the Project and the annual audit report by sending a written request therefor to Energy Northwest.

Consulting Engineer: Energy Northwest will retain a nationally recognized independent consulting engineer or engineering firm to render continuous engineering counsel in the operation of each Net Billed Project. In addition to his other duties, the Consulting Engineer shall prepare, not later than 18 months after the respective Date of Commercial Operation of each Net Billed Project, and each three years thereafter, a report for each such Project based upon a survey of such Project and the operation and maintenance thereof. Each report is to show, among other things, whether Energy Northwest has satisfactorily performed and complied with certain covenants in the related Prior Lien Resolution. The Consulting Engineer is also required to report to the respective Bond Fund Trustee and Energy Northwest upon the economic soundness and feasibility of all contemplated renewals, replacements, additions, betterments and improvements to, and extensions of, Project 1, Columbia and Project 3 involving an expenditure of, in the case of Projects 1 and 3, $500,000 or more, and, in the case of Columbia, $100,000 or more. The Consulting Engineer is also required to file annually a certificate with each Bond Fund Trustee describing the insurance then in effect for the respective Project and stating whether or not such insurance complies with the requirements of the related Prior Lien Resolution. In the event of any loss or damage, in the case of Projects 1 and 3, in excess of $500,000, and, in the case of Columbia, in excess of $100,000, whether or not covered by insurance, the Consulting Engineer is to ascertain the amount of such loss or damage and deliver to Energy Northwest a certificate setting forth the amount and nature of such loss or damage, together with recommendations as to whether or not such loss or damage should be replaced or repaid. Copies of any such triennial report, annual certificate as to insurance or certificate in respect of any such loss or damage will be sent to Bondholders filing with Energy Northwest written requests therefor.

Events of Default; Remedies

Under each Prior Lien Resolution, the happening of one or more of the following events constitutes an Event of Default: (i) default in the performance of any obligation with respect to payments into the respective Revenue Fund; (ii) default in the payment of the principal of and premium, if any, or default for 30 days in the payment of interest on any of the respective Prior Lien Bonds or any sinking fund installment on any Project 1 or Columbia Prior Lien Bonds; (iii) default for 90 days in the observance and performance of any other of the covenants, conditions and agreements of Energy Northwest in the respective Prior Lien Resolution; (iv) the sale or conveyance of any properties of the respective Net Billed Project except as permitted by the respective Net Billed Resolution or the voluntary forfeiture of any license, franchise, permit or other privilege necessary or desirable in the operation of such Project; (v) the entering by any court of competent jurisdiction of an order, judgment or decree (a) appointing a receiver, trustee or liquidator for Energy Northwest or the whole or any substantial part of the respective Net Billed Project, (b) approving a petition filed against Energy Northwest under Federal bankruptcy laws, or (c) assuming custody or control of Energy Northwest or of the whole or any substantial part of the respective Net Billed Project under the provisions of any other law for the relief or aid of debtors and such order, judgment or decree shall not be vacated or set aside or stayed (or, in case custody or control is assumed by said order, such custody or control shall not be otherwise terminated), within 60 days from the date of the entry of such order, judgment or decree; or (vi) Energy Northwest (a) admits in writing its inability to pay its debts incurred in the ownership and operation of the respective Net Billed Project generally as they become due, (b) files a petition in bankruptcy or seeking a composition of indebtedness, (c) consents to the appointment of a receiver of its creditors, (d) consents to the appointment of a receiver of the whole or any substantial part of the respective Net Billed Project, (e) files a petition or an answer seeking relief under Federal bankruptcy laws, or (f) consents to the assumption by any court of competent jurisdiction under the provisions of any other law for the relief or aid of debtors of custody or control of Energy Northwest or of the whole or any substantial part of the respective Net Billed Project.

If an Event of Default shall have occurred and shall not have been remedied, the respective Bond Fund Trustee or the holders of not less than 20% in principal amount of the respective Prior Lien Bonds then outstanding under the related Prior Lien Resolution, may declare the principal of all such Bonds and the interest accrued thereon to be immediately due and payable, but such declaration may be annulled under certain circumstances.

The applicable Bond Fund Trustee or the holders of not less than 20% in principal amount of Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds (as the case may be) shall have the right to declare the Project 1

Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds immediately due and payable only upon the occurrence and continuance of an Event of Default described in clauses (i), (ii), (v), or (vi) in the second preceding paragraph.

After the occurrence of an Event of Default and prior to the curing of such Event of Default, the Bond Fund Trustee of the Net Billed Project in default may, to the extent permitted by law, take possession and control of such Net Billed Project and operate and maintain the same, prescribe rates for capability or power sold or supplied through the facilities of such Project, collect the gross revenues resulting from such operation and perform all of the agreements and covenants contained in any contract which Energy Northwest is then obligated to perform. Such gross revenues, after payment of reasonable and proper charges, expenses and liabilities paid or incurred by the Bond Fund Trustee and operating expenses of the related Net Billed Project, and, in the case of Project 1, after additional payment of the amounts required by the Project 1 Prior Lien Resolution to be paid into the Hanford Project Revenue Fund, shall be applied to the payment of principal of and interest on the defaulting Net Billed Project's Bonds. Each Prior Lien Resolution provides that, in the event that at any time the funds held by the applicable Bond Fund Trustee and the Paying Agents for Prior Lien Bonds in default shall be insufficient for the payment of the principal of and premium, if any, and interest then due on such Prior Lien Bonds, such funds (other than funds held for the payment or redemption of particular Bonds which have theretofore become due at maturity or by call for redemption) and all revenues and other moneys received or collected for the benefit or for the account of holders of such Bonds by the applicable Bond Fund Trustee shall be applied as follows:

(1) Unless the principal of all such Bonds shall have become or have been declared due and payable,

First, to the payment of all installments of interest then due in the order of the maturity of such installments and, if the amount available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon; and

Second, to the payment of the unpaid principal and premium, if any, of any such Bonds which shall become due, whether at maturity or by call for redemption, in the order of their due dates and, if the amount available shall not be sufficient to pay in full all amounts due on any date, then to the payment thereof ratably, according to the amounts of principal and premium, if any, due on such date.

(2) If the principal of all of such Bonds shall have become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon such Bonds without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any Bond over any other Bond, ratably, according to the amounts of principal and interest due.

After all sums then due in respect of such Bonds have been paid, and after all Events of Default have been cured or secured to the satisfaction of the defaulting Net Billed Project's Bond Fund Trustee, such Bond Fund Trustee is required to relinquish possession and control of such Net Billed Project to Energy Northwest.

The Prior Lien Resolutions empower each Bond Fund Trustee to file proofs of claims for the benefit of the holders of the defaulting Net Billed Project's Bonds in bankruptcy, insolvency or reorganization proceedings and to institute suit for the collection of sums due and unpaid in connection with such Bonds, to enforce specific performance of covenants contained in the Prior Lien Resolution governing the Net Billed Project in default or to obtain injunctive or other appropriate relief for the protection of the holders of such Net Billed Bonds.

The holders of a majority in principal amount of the defaulting Net Billed Project's Prior Lien Bonds at the time outstanding have the right to direct the time, method and place of conducting any proceeding for any remedy available to the defaulting Net Billed Project's Bond Fund Trustee, or exercising any trust or power conferred upon such Bond Fund Trustee, but such Bond Fund Trustee must be provided with reasonable security and indemnity and also may decline to follow any such direction if it shall be advised by counsel that the action or proceeding so directed may not lawfully be taken or if it in good faith determines that the action or proceeding so directed would involve it in personal liability or that the action or proceeding so directed would be unjustly prejudicial to the holders of such Bonds not parties to such direction. No holder of any Prior Lien Bond has any right to institute suit to enforce any provision of the respective Prior Lien Resolution or the execution of any trust thereunder (except to enforce the payment of principal or interest installments as they mature), unless the respective Bond Fund Trustee has been requested by the holders of not less than 20% in aggregate principal amount of such Bonds then outstanding to exercise the powers granted it by such Resolution or to institute such suit and unless such Bond Fund Trustee has failed or refused to comply with the aforesaid request.

Amendments; Supplemental Resolutions

Any amendment to a Prior Lien Resolution in any particular, except the percentage of Bondholders the approval of which is required to approve such amendment, may be made by Energy Northwest with the consent of the holders of $66^2/_3$% in principal amount of the Prior Lien Bonds issued pursuant to such Resolution then outstanding and with the consent of the holders of $66^2/_3$% in principal amount of such outstanding Bonds which are adversely affected by an amendment which does not equally affect all other such outstanding Bonds, provided that no such amendment shall permit a change in the date of payment of principal of or any installment of interest on any such Bond or a reduction in the principal or redemption price thereof or the rate of interest thereon without the consent of each such Bondholder so affected.

Without the consent of Bondholders, Energy Northwest may adopt supplemental resolutions for any of, but not limited to, the following purposes: (i) to authorize the issuance of subsequent Series of Project 1, Columbia or Project 3 Prior Lien Bonds; (ii) to add to the covenants of Energy Northwest contained in, or to surrender any rights reserved to or conferred upon it by, a Prior Lien Resolution; (iii) to add to the restrictions contained in a Prior Lien Resolution upon the issuance of additional indebtedness; (iv) to confirm as further assurance any pledge under a Prior Lien Resolution of the revenues of the respective Net Billed Project or other moneys; (v) otherwise to modify any of the provisions of a Prior Lien Resolution (but no such modification may be effective while any of the Prior Lien Bonds theretofore issued pursuant to such Resolution are outstanding); or (vi) to cure any ambiguity or defect or inconsistent provision in such Resolution or to insert such provisions clarifying matters or questions arising under such Resolution as necessary or desirable in the event any such modifications are not contrary to or inconsistent with such Resolution or, in the case of the Project 3 Prior Lien Resolution, not adverse to the rights and interests of the holders of the Project 3 Prior Lien Bonds, provided that the appropriate Bond Fund Trustee shall consent thereto.

Supplemental resolutions may be adopted for purposes described in clause (vi) of the preceding paragraph if such modifications are not adverse to the rights and interests of the holders of the Project 1 Prior Lien Bonds, Columbia Prior Lien Bonds or Project 3 Prior Lien Bonds, as the case may be.

Defeasance

The obligations of Energy Northwest under a Prior Lien Resolution shall be fully discharged and satisfied as to any related Prior Lien Bond, and such Bond shall no longer be deemed to be outstanding thereunder when payment of the principal of and the applicable redemption premium, if any, on such Bond plus interest to the due date thereof (a) shall have been made or caused to be made in accordance with the terms thereof, or (b) shall have been provided by irrevocably depositing with the Bond Fund Trustee or the Paying Agents therefor in trust solely for such payment (i) moneys sufficient to make such payments or (ii) Investment Securities described in clauses (i) through (iv) under “Investment of Funds” in this Appendix H-2 maturing as to principal and interest in such amounts and at such times as will insure the availability of sufficient moneys to make such payment, and, except for the purposes of such payment, such Bond shall no longer be secured by or entitled to the benefits of such Prior Lien Resolution; provided that, with respect to Prior Lien Bonds which by their terms may be redeemed or otherwise prepaid prior to the stated maturities thereof but are not then redeemable, no deposit under (b) above shall constitute such discharge and satisfaction unless such Bonds shall have been irrevocably called or designated for redemption on the first date thereafter such Bonds may be redeemed in accordance with the provisions thereof and notice of such redemption shall have been given or irrevocable provision shall have been made for the giving of such notice.

BOOK-ENTRY SYSTEM

The following information has been provided by the Depository Trust Company, New York, New York ("DTC"). Energy Northwest makes no representation regarding the accuracy or completeness thereof. Beneficial Owners (as hereinafter defined) should therefore confirm the following with DTC or the DTC Participants (as hereinafter defined).

DTC will act as securities depository for the 2006 Bonds. The 2006 Bonds will be issued as fully-registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate will be issued for each maturity of the 2006 Bonds in the principal amount of such maturity and will be deposited with DTC.

DTC, the world's largest securities 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 2.2 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation and Emerging Markets Clearing Corporation, (NSCC, FICC, 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 DTC Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the 2006 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 2006 Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2006 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2006 Bonds, except in the event that use of the book entry-entry system for the 2006 Bonds is discontinued.

To facilitate subsequent transfers, all 2006 Bonds deposited by DTC Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of 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 2006 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 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 2006 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2006 Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Energy Northwest as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the 2006 Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from Energy Northwest or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by DTC Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such DTC Participant and not of DTC, the Bond Registrar, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2006 Bonds at any time by giving reasonable notice to Energy Northwest and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, Bond certificates are required to be printed and delivered.

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

With respect to Bonds registered on the Bond Register in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Bond Registrar shall have no responsibility or obligation to any DTC Participant or to any person on behalf of whom a DTC Participant holds an interest in the 2006 Bonds with respect to (i) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the 2006 Bonds; (ii) the delivery to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any notice with respect to the 2006 Bonds, including any notice of redemption; (iii) the payment to any DTC Participant or any other person, other than a bondowner as shown on the Bond Register, of any amount with respect to principal of, premium, if any, or interest on the 2006 Bonds; (iv) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the 2006 Bonds; (v) any consent given action taken by DTC as registered owner; or (vi) any other matter. Energy Northwest and the Bond Registrar may treat and consider Cede & Co., in whose name each Bond is registered on the Bond Register, as the holder and absolute owner of such Bond for the purpose of payment of principal and interest with respect to such Bond, for the purpose of giving notices of redemption and other matters with respect to such Bond, for the purpose of registering transfers with respect to such Bond, and for all other purposes whatsoever. For the purposes of this Official Statement, the term "Beneficial Owner" shall include the person for whom the DTC Participant acquires an interest in the 2006 Bonds.

SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville will enter into a written agreement (the "Agreement") for the benefit of the holders and beneficial owners of the 2006 Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Agreement, which apply to any capitalized term used in the Agreement, the following capitalized terms shall have the following meanings:

"BPA Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2006 Bonds in the following tables in Appendix A under the heading "THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS": "Federal System Statement of Revenues and Expenses," "Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments" and "Statement of Net Billing Obligations and Expenditures."

"Energy Northwest Annual Information" means financial information and operating data generally of the type included in the final Official Statement for the 2006 Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of March 1, 2006" under the heading "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" and in the table labeled "Statement of Operations" under the heading "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION —Annual Costs."

"Energy Northwest Fiscal Year" means the fiscal year ending each June 30 or, if such fiscal year end is changed, on such new date; provided that if the Energy Northwest Fiscal Year end is changed, Energy Northwest shall provide written notice of such change to each NRMSIR and the SID, if any.

"FCRPS" shall mean the Federal Columbia River Power System.

"FCRPS Fiscal Year" shall mean the fiscal year ending each September 30 or, if such fiscal year end is changed, on such new date; provided that if the FCRPS Fiscal Year end is changed, Bonneville shall provide written notice of such change to each NRMSIR and the SID, if any.

"MSRB" means the Municipal Securities Rulemaking Board or any successors to its functions.

"NRMSIR" means a nationally recognized municipal securities information repository.

"Rule 15c2-12" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of this Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Agreement.

"SID" means a state information depository for the State of Washington, if any.

Financial Information.

Bonneville. Bonneville agrees to provide to each NRMSIR (or provide to a transmitting entity approved by the SEC) and to the SID, if any, in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2006:

(i) the BPA Annual Information for the FCRPS Fiscal Year; and

(ii) annual financial statements of the FCRPS for the FCRPS Fiscal Year, prepared in accordance with generally accepted accounting principles; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not the audited annual financial statements of FCRPS, Bonneville shall provide such audited annual financial statements when and if they become available.

Bonneville shall notify Energy Northwest when such BPA Annual Information has been provided and when such financial statements have been provided.

Energy Northwest. Energy Northwest agrees to provide to each NRMSIR and to the SID, if any (or provide to a transmitting entity approved by the SEC), in each case as designated by the SEC in accordance with the Rule, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with Energy Northwest Fiscal Year ending June 30, 2006:

(i) the Energy Northwest Annual Information for the Energy Northwest Fiscal Year; and

(ii) annual financial statements of Energy Northwest for the Energy Northwest Fiscal Year, prepared in accordance with generally accepted accounting principles applicable to governmental entities; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not its audited annual financial statements, Energy Northwest shall provide its audited annual financial statements when and if they become available.

Cross-Reference. In lieu of providing the annual financial information and operating data described in A and B above, Bonneville and Energy Northwest may cross-refer to other documents provided to the NRMSIR, the SID, if any, or to the SEC (or transmitting entity approved by the SEC) and, if such document is a final official statement within the meaning of the Rule, available from the MSRB.

Notice of Failure to Provide Financial Information. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to each NRMSIR or to the MSRB and to the SID, if any (or provide to a transmitting entity approved by the SEC), (i) notice of Bonneville's failure to provide the annual financial information described in A above on or prior to the applicable date set forth in A above and (ii) notice of Energy Northwest's failure to provide the annual financial information described in B above on or prior to the applicable date set forth in B above.

Material Events Notices.

Energy Northwest 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 (or provide to a transmitting entity approved by the SEC), notice of the occurrence of any of the following events with respect to the 2006 Bonds, if material:

(i) Principal and interest payment delinquencies;

(ii) Non-payment related defaults;

(iii) Unscheduled draws on debt service reserves reflecting financial difficulties;

(iv) Unscheduled draws on credit enhancements reflecting financial difficulties;

(v) Substitution of credit or liquidity providers, or their failure to perform;

(vi) Adverse tax opinions or events affecting the tax-exempt status of the 2006-A Bonds or Series 2006-C Bonds;

(vii) Modifications to rights of 2006 Bondholders;

(viii) Optional, contingent or unscheduled calls of any 2006 Bonds other than scheduled sinking fund redemptions for which notice is given pursuant to Exchange Act Release 34-23856;

(ix) Defeasances;

(x) Release, substitution or sale of property securing repayment of the 2006 Bonds; and

(xi) Rating changes.

Solely for purposes of disclosure, and not intending to modify this undertaking, Energy Northwest advises with reference to items (iii) and (x) above that no debt service reserves or property secure payment of the 2006 Bonds.

Termination, Modification.

The obligations of Bonneville and Energy Northwest to provide annual financial information and the obligation of Energy Northwest to provide notices of material events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2006 Bonds. This section, or any provision hereof, shall be null and void if Bonneville and Energy Northwest

(i) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule that require this Disclosure Agreement, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the 2006 Bonds; and (ii) notifies each then existing NRMSIR (or transmitting entity approved by the SEC) and the SID, if any, of such opinion and the cancellation of this Disclosure Agreement.

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

Remedies.

The right of any Owner or Beneficial Owner of 2006 Bonds to enforce the provisions of this Disclosure Agreement against Energy Northwest shall be limited to a right to obtain specific enforcement of Energy Northwest's obligations hereunder, and any failure by Energy Northwest to comply with the provisions of this Disclosure Agreement shall not be an event of default under the Resolution or the Supplemental Resolution or with respect to the 2006 Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Disclosure Agreement. Owners and Beneficial Owners of 2006 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.