NEW ISSUE — BOOK-ENTRY ONLY

Series 2005-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 2005-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 "Code"). In the further opinion of Special Tax Counsel, interest on the Series 2005-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 2005-B (Taxable) Bonds: In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2005-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act or Section 103 of the Code. See "TAX MATTERS" herein.

$320,010,000
Energy Northwest

$72,175,000 Project 1 Electric Revenue Refunding Bonds, Series 2005-A
$114,985,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A
$129,265,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-A

$925,000 Project 1 Electric Revenue Refunding Bonds, Series 2005-B (Taxable)
$1,600,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable)
$1,060,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-B (Taxable)

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

The Series 2005-A and the Series 2005-B (Taxable) Bonds (together, the "2005 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 2005 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 2005 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 2005 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 2005 Bonds. Principal of the 2005 Bonds is payable at the principal office of The Bank of New York Trust Company, N.A., Seattle, Washington, as Trustee for the 2005 Bonds. Interest on the 2005 Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 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 2005 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 2005 BONDS – GENERAL — Book Entry Only System; Transferability and Registration" and Appendix I — "BOOK-ENTRY SYSTEM" herein.

*Certain of the Series 2005-A Bonds are subject to redemption prior to maturity as set forth herein. The Series 2005-B (Taxable) Bonds are not subject to redemption prior to maturity. See "*DESCRIPTION OF THE 2005 BONDS — REDEMPTION*" herein.*

The 2005 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

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 2005 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 2005 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.

Payment when due of the principal of and interest on certain maturities of the 2005 Bonds as shown on the inside cover will be insured by a financial guaranty insurance policy to be issued by Ambac Assurance Corporation simultaneously with the delivery of the 2005 Bonds. See "SECURITY FOR THE NET BILLED BONDS – BOND INSURANCE" herein.

MATURITY SCHEDULE — See Inside Cover

The 2005 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. 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 2005 Bonds will be available for delivery through the facilities of DTC on or about May 26, 2005.

Citigroup **Goldman, Sachs & Co.**
JPMorgan **Prager, Sealy & Co., LLC**
Seattle-Northwest Securities Corporation **UBS Financial Services Inc.**

May 19, 2005

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, YIELDS AND PRICES

THE SERIES 2005-A BONDS

$72,175,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013†	$ 20,810,000	5.00%	3.60%	29270CKF1
2014†	26,365,000	5.00	3.69	29270CKG9
2015†	25,000,000	5.00	3.78	29270CKH7

$114,985,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2015	$ 16,035,000	5.00%	3.83%	29270CKJ3
2016†	32,985,000	5.00	3.86**	29270CKK0
2017	32,985,000	5.00	3.97**	29270CKL8
2018†	32,980,000	5.00	3.96**	29270CKM6

$129,265,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Yield	CUSIP*
2013†	$ 50,475,000	5.00%	3.60%	29270CKN4
2014	46,065,000	5.00	3.74	29270CKP9
2015†	32,725,000	5.00	3.78	29270CKQ7

THE SERIES 2005-B (TAXABLE) BONDS

$925,000 Project 1 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2008†	$ 925,000	4.11%	100%	29270CKR5

$1,600,000 Columbia Generating Station Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2008†	$ 1,600,000	4.11%	100%	29270CKS3

$1,060,000 Project 3 Electric Revenue Refunding Bonds

Year (July 1)	Amount	Interest Rate	Price	CUSIP*
2008†	$ 1,060,000	4.11%	100%	29270CKT1

 CUSIP data herein are provided by Standard & Poor's CUSIP Service Bureau, a division of The McGraw-Hill Companies, Inc. The CUSIP numbers listed above are being provided solely for the convenience of Bondowners only at the time of issuance of the 2005 Bonds and Energy Northwest makes no representation with respect to such numbers and undertakes no responsibility for their accuracy now or at any time in the future. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2005 Bonds as a result of various subsequent actions, including, but not limited to, a refunding in whole or in part of such maturity or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2005 Bonds.

** Priced to the July 1, 2015 par call date.

† Insured by Ambac Assurance Corporation.

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

Executive Board Members

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 2005 Bonds
The Bank of New York Trust Company, N.A.

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

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
Acting Chief Financial Officer	Nancy Mitman

Special 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, nor shall there be any sale of the 2005 Bonds, by 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.

Other than with respect to information concerning Ambac Assurance Corporation ("Ambac") contained under "SECURITY FOR NET BILLED BONDS - Bond Insurance" and Appendix K "AMBAC SPECIMEN FINANCIAL GUARANTY INSURANCE POLICY" herein, none of the information in this Official Statement has been supplied or verified by Ambac, and Ambac makes no representation or warranty, express or implied, as to: (i) the accuracy or completeness of such information; (ii) the validity of the 2005 Bonds, or (iii) the tax exempt status of the interest on the Series 2005-A Bonds.

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

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 2005 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH 2005 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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$320,010,000

ENERGY NORTHWEST

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$114,985,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A

$129,265,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-A

$925,000 Project 1 Electric Revenue Refunding Bonds, Series 2005-B (Taxable)

$1,600,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable)

$1,060,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-B (Taxable)

INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover page hereof and the appendices hereto, in connection with the sale of the 2005 Bonds (hereinafter defined).

This Introduction is not intended to provide all information material to a prospective purchaser of the 2005 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 $72,175,000 Project 1 Electric Revenue Refunding Bonds, Series 2005-A (the "Project 1 2005-A Bonds"), $114,985,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A (the "Columbia 2005-A Bonds"), $129,265,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-A (the "Project 3 2005-A Bonds," and together with the Project 1 2005-A Bonds and the Columbia 2005-A Bonds, the "Series 2005-A Bonds") and $925,000 Project 1 Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Project 1 2005-B (Taxable) Bonds"), $1,600,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Columbia 2005-B (Taxable) Bonds") and $1,060,000 Project 3 Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Project 3 2005-B (Taxable) Bonds," and together with the Project 1 2005-B (Taxable) Bonds and the Columbia 2005-B (Taxable) Bonds, the "Series 2005-B (Taxable) Bonds"). The Series 2005-A Bonds and Series 2005-B (Taxable) Bonds are together referred to herein as the "2005 Bonds."

The Project 1 2005-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 2005-B (Taxable) Bonds (together with the Project 1 2005-A Bonds, the "Project 1 2005 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 2005 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 2005-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 2005-B (Taxable) Bonds (together with the Columbia 2005-A Bonds, the "Columbia 2005 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 2005-A Bonds and the Columbia 2005-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 2005-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"). The Project 3 2005-B (Taxable) Bonds (together with the Project 3 2005-A Bonds, the "Project 3 2005 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 2005 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 2005 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."

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 name-plate 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 30 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, Utah and Wyoming (sometimes referred to herein as the "Pacific Northwest," the "Northwest," the "Region," or "Regional"). Bonneville estimates that this 300,000 square mile service area has a population of approximately ten million people. Electric power sold by Bonneville accounts for about 45% of the electric power consumed within the Region. Bonneville also exports power that is surplus to the needs of the Region to the Pacific Southwest, primarily to California.

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

THE 2005 BONDS

The Project 1 2005 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2005 Bonds are secured, on a subordinated basis to the Project 1 Prior Lien Bonds, which are outstanding under the Project 1 Prior Lien Resolution, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2005 Bonds are secured on parity with the Project 1 Electric Revenue Bonds, which are outstanding pursuant to the Project 1 Electric Revenue Bond Resolution, 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.

The Columbia 2005 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2005 Bonds are secured, on a subordinated basis to the Columbia Prior Lien Bonds, which are outstanding under the Columbia Prior Lien Resolution, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership and operation of Columbia. The Columbia 2005 Bonds are secured on parity with the Columbia Electric Revenue Bonds, which are outstanding pursuant to the Columbia Electric Revenue Bond Resolution, 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.

The Project 3 2005 Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2005 Bonds are secured, on a subordinated basis to the Project 3 Prior Lien Bonds, which are outstanding under the Project 3 Prior Lien Resolution, by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2005 Bonds are secured on parity with the Project 3 Electric Revenue Bonds, which are outstanding pursuant to the Project 3 Electric Revenue Bond Resolution, 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.

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 2005 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 2005 Bonds relating to that Project. Accordingly, the owners of the 2005 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 April 1, 2005, 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 are not 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.

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."

DESCRIPTION OF THE 2005 BONDS

GENERAL

The 2005 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 January 1, 2006, at the rates shown on the inside cover of this Official Statement. Interest on the 2005 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 2005 Bonds (collectively, the "Trustee"). For so long as the 2005 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 2005 Bonds are no longer registered in the name of Cede & Co., interest on the 2005 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. Principal of the 2005 Bonds is payable at the office of the Trustee in Seattle, Washington; 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 2005 Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States.

Book-Entry Only System; Transferability and Registration

The 2005 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 2005 Bonds will not receive certificates representing their interests in such 2005 Bonds purchased, except as described in Appendix I — "BOOK-ENTRY SYSTEM." DTC will act as securities depository ("Securities Depository") for each Series of 2005 Bonds. As discussed in Appendix I — "BOOK-ENTRY SYSTEM," transfers of ownership interests in the 2005 Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants acting on behalf of Beneficial Owners of the 2005 Bonds. Energy Northwest, the Trustee and any other person may treat the Registered Owner of any 2005 Bond as the absolute owner of such 2005 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 2005 Bond shall be overdue or not. All payments of or on account of interest or principal to any Registered Owner of any such 2005 Bond shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such 2005 Bond, to the extent of the sum or sums paid.

When 2005 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 Participant (as defined in Appendix I — "BOOK-ENTRY SYSTEM") or to any person on behalf of whom a Participant holds an interest in the 2005 Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any Participant with respect to any ownership interest in the 2005 Bonds, (2) the delivery to any Participant or any other person, other than a Registered Owner as shown on the Bond Register, of any notice with respect to the 2005 Bonds, including any notice of redemption, (3) the payment to any 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 2005 Bonds, (4) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the 2005 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 2005 Bond is registered, as the holder and absolute owner of such 2005 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 2005 Bonds, 2005 Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the 2005 Bonds shall be payable upon due presentment and surrender thereof at the principal office of the Trustee, and interest on the 2005 Bonds will be payable by check or draft mailed to the persons in whose names such 2005 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 2005 Bonds is discontinued, registered ownership of any 2005 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 2005 Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

The Project 1 2005-A Bonds are not subject to redemption prior to maturity.

The Columbia 2005-A Bonds maturing on and after July 1, 2016 will be subject to redemption prior to maturity at the option of Energy Northwest on and after July 1, 2015, 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 2005-A Bonds are not subject to redemption prior to maturity.

The Series 2005-B (Taxable) Bonds are not subject to redemption prior to maturity.

Notice of Redemption

Notice of redemption of the Columbia 2005-A 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 Columbia 2005-A Bonds which are to be redeemed at their last addresses shown on the registration books for the Columbia 2005-A Bonds. Such notice shall be deemed conclusively to be received by the Registered Owners of the Columbia 2005-A 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 Columbia 2005-A Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Columbia 2005-A 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 Columbia 2005-A Bonds to be redeemed, together with interest thereon to the redemption date, are held by the Trustee for such Columbia 2005-A Bonds on the redemption date and the Columbia 2005-A 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 only system is in effect with respect to the Columbia 2005-A Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Columbia 2005-A 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 Columbia 2005-A 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 Columbia 2005-A Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Columbia 2005-A 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 Columbia 2005-A Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any 2005 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 2005 Bond and such 2005 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 2005 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 2005 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 moneys to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agents pertaining to such 2005 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 2005 Bonds.

PURPOSE OF ISSUANCE

REFUNDING PROGRAM

In 2000, Bonneville presented its Debt Optimization Proposal (the "Bonneville Proposal") to Energy Northwest. The Bonneville Proposal involves the extension of the final maturity to 2018 of outstanding Columbia Net Billed Bonds coming due prior to 2012 through a series of refunding bond issues. A portion of the Columbia 2005-A Bonds and the Columbia 2005-B (Taxable) Bonds are being issued for such purpose. 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 meet Bonneville's financial requirements. Implementing the Bonneville Proposal is intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's high interest Federal debt and reduce Bonneville's overall fixed costs.

Energy Northwest, in response to the Bonneville Proposal, developed its 2000 Refunding Plan essentially adopting the Bonneville Proposal. The 2000 Refunding Plan also reaffirmed the historical debt service savings goals for any future refinancing of Projects 1 and 3 and Columbia Net Billed Bonds. The Executive Board of Energy Northwest formally adopted the 2000 Refunding Plan in October 2000.

In September 2001, Energy Northwest's Executive Board adopted an updated Refunding Plan. Such Refunding Plan included a revision which incorporated the increase in the average life of outstanding Projects 1 and 3 Net Billed Bonds through the extension of the maturity of such Bonds as a refinancing program objective for any future refinancing of such Bonds. The Project 1 and Project 3 2005 Bonds are being issued for such purpose. An additional objective of the refinancing program is to advance refund outstanding, noncallable Net Billed Bonds when deemed appropriate by Energy Northwest and Bonneville.

In furtherance of the Refunding Program, in July 2004, 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 $50,635,000, $119,025,000 and $84,685,000, respectively, from time to time during the period from July 1, 2004 to June 30, 2005. 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, 2005 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 April 1, 2005, Energy Northwest had borrowed $33,756,666, $71,546,633 and $47,392,090 under the Project 1, Columbia and Project 3 Credit Agreements, respectively. Energy Northwest expects to borrow additional amounts prior to the issuance of the 2005 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 2005-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 2005, substantially similar to the Credit Agreements entered into in 2004, for the purpose of extending the maturity of the Net Billed Bonds maturing in 2006.

REFUNDED OBLIGATIONS

The Project 1 2005-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $42,195,833 Project 1 Note) of refunding (i) $72,700,000 aggregate principal amount of the Project 1 Prior Lien Bonds and (ii)

$5,875,000 aggregate principal amount of the Project 1 Electric Revenue Bonds and paying a portion of the costs of issuance of the Project 1 2005-A Bonds.

The Columbia 2005-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $95,285,817 Columbia Note) of refunding (i) $119,025,000 aggregate principal amount of the Columbia Prior Lien Bonds and (ii) $6,270,000 aggregate principal amount of the Columbia Electric Revenue Bonds.

The Project 3 2005-A Bonds are being issued for the purpose (directly or indirectly through repayment of the $66,038,545 Project 3 Note) of refunding (i) $135,970,000 aggregate principal amount of Project 3 Prior Lien Bonds and (ii) $6,980,000 aggregate principal amount of Project 3 Electric Revenue Bonds and paying a portion of the costs of issuance of the Project 3 2005-A Bonds.

The Project 1 2005-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 1 2005-A Bonds and Project 1 2005-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 2005-B (Taxable) Bonds are being issued for the purpose of paying certain costs relating to the issuance of the Columbia 2005-A Bonds and Columbia 2005-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 2005-B (Taxable) Bonds are being issued for the purpose of paying costs relating to the issuance of the Project 3 2005-A Bonds and the Project 3 2005-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 2005-A Bonds and the Series 2005-B (Taxable) Bonds and other available amounts will be used to purchase 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 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 to be refunded to the date of their retirement and (2) the mathematical computations of the yields on the Series 2005-A Bonds and the adjusted yields on the investments acquired with the proceeds of the Series 2005-A Bonds will be verified by Bond Logistix LLC.

Information relating to the Prior Lien Bonds and Electric Revenue Bonds to be paid or redeemed with the proceeds of the 2005 Bonds and other funds is set forth as follows:

Prior Lien Bonds:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Payment Date
1	1992A	$ 720,000	2006	6.10%	July 1, 2006
1	1993A	1,140,000	2005	5.60	July 1, 2005
1	1993A	18,430,000	2006	5.70	July 1, 2006
1	1993B	6,165,000	2005	5.40	July 1, 2005
1	1993B	2,915,000	2006	5.50	July 1, 2006
1	1993C	1,710,000	2005	5.00	July 1, 2005
1	1996A	33,070,000	2005	6.00	July 1, 2005
1	1996B	765,000	2005	6.00	July 1, 2005
1	1996C	435,000	2005	5.10	July 1, 2005
1	1997B	980,000	2005	5.00	July 1, 2005
1	1998A	6,370,000	2005	5.00	July 1, 2005
Columbia	1990C*	35,000,000	2005	0.00	July 1, 2005
Columbia	1993A	14,805,000	2005	5.60	July 1, 2005
Columbia	1993B	15,395,000	2005	5.40	July 1, 2005
Columbia	1994A	20,210,000	2005	4.90	July 1, 2005
Columbia	1996A	9,865,000	2005	6.00	July 1, 2005
Columbia	1997B	5,000,000	2005	5.50	July 1, 2005
Columbia	1998A	18,750,000	2005	5.00	July 1, 2005
3	1989A*	4,125,000	2005	0.00	July 1, 2005
3	1989A*	4,125,000	2006	0.00	July 1, 2006
3	1989B*	25,000,000	2005	0.00	July 1, 2005
3	1989B*	25,000,000	2006	0.00	July 1, 2006
3	1990B*	12,000,000	2005	0.00	July 1, 2005
3	1990B*	12,000,000	2006	0.00	July 1, 2006
3	1993B	9,615,000	2005	5.40	July 1, 2005
3	1993B	10,160,000	2006	5.50	July 1, 2006
3	1993C	21,910,000	2005	5.00	July 1, 2005
3	1996A	335,000	2005	5.50	July 1, 2005
3	1997A	550,000	2005	5.00	July 1, 2005
3	1998A	11,150,000	2005	5.00	July 1, 2005

Electric Revenue Bonds:

Project	Series	Amount**	Maturity (July 1)	Interest Rate	Redemption Date	Redemption Price
1	1993-1A	$ 5,875,000	2017	variable	July 1, 2005	100%
Columbia	1997-2A	6,270,000	2012	variable	July 1, 2005	100
3	1993-3A	980,000	2018	variable	July 1, 2005	100
3	1998-3A	6,000,000	2018	variable	July 1, 2005	100

* Value at maturity of Compound Interest Bonds.

** Scheduled sinking fund redemption installment.

ESTIMATED SOURCES AND USES OF FUNDS

SOURCES OF FUNDS:

Project 1

Principal of Project 1 2005-A Bonds	$ 72,175,000
Principal of Project 1 2005-B (Taxable) Bonds	925,000
Net Original Issue Premium Project 1 Bonds	7,216,617
Moneys Available Under Project 1 Prior Lien Resolution	43,581,430
Total	$ 123,898,047

Columbia

Principal of Columbia 2005-A Bonds	$ 114,985,000
Principal of Columbia 2005-B (Taxable) Bonds	1,600,000
Net Original Issue Premium Columbia Bonds	10,309,272
Moneys Available Under Columbia Prior Lien Resolution	96,770,850
Total	$ 223,665,122

Project 3

Principal of Project 3 2005-A Bonds	$ 129,265,000
Principal of Project 3 2005-B (Taxable) Bonds	1,060,000
Net Original Issue Premium Project 3 Bonds	12,686,360
Moneys Available Under Project 3 Prior Lien Resolution	66,964,190
Total	$ 209,975,550

USES OF FUNDS:

Project 1

Deposit with escrow trustee for refunded Project 1 Prior Lien Bonds	$ 74,978,368
Deposit with escrow trustee for refunded Project 1 Electric Revenue Bonds	5,857,738
Project 1 Note Repayment	42,195,833
Costs of Issuance*	866,108
Total	$ 123,898,047

Columbia

Deposit with escrow trustee for refunded Columbia Prior Lien Bonds	$ 120,896,079
Deposit with escrow trustees for refunded Columbia Electric Revenue Bonds	6,251,576
Columbia Note Repayment	95,285,817
Costs of Issuance*	1,231,650
Total	$ 223,665,122

Project 3

Deposit with escrow trustee for refunded Project 3 Prior Lien Bonds	$ 135,658,217
Deposit with escrow trustee for refunded Project 3 Electric Revenue Bonds	6,959,489
Project 3 Note Repayment	66,038,545
Costs of Issuance*	1,319,299
Total	$ 209,975,550

* Includes underwriters' compensation and bond insurance premium.

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2005 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 ($892,890,000 of which were outstanding as of April 1, 2005), to the lien and pledge of the Project 1 Prior Lien Resolution. The Project 1 2005 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 2005 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 2005 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 April 1, 2005, $1,084,435,000 principal amount of Project 1 Electric Revenue Bonds.

The Columbia 2005 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 ($885,990,000 of which were outstanding as of April 1, 2005), to the lien and pledge of the Columbia Prior Lien Resolution. The Columbia 2005 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 2005 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 2005 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 April 1, 2005, $1,274,065,000 principal amount of Columbia Electric Revenue Bonds.

The Project 3 2005 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 ($874,470,000 of which were outstanding as of April 1, 2005), to the lien and pledge of the Project 3 Prior Lien Resolution. The Project 3 2005 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 2005 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 2005 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 April 1, 2005, $1,060,320,000 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 2005 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 2005 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 2005 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 2005 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 2005 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 2005 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 2005 Bonds, the Columbia 2005 Bonds and the Project 3 2005 Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2005 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2005 Bonds and the Project 3 2005 Bonds. The owners of the Columbia 2005 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2005 Bonds and the Project 3 2005 Bonds. The owners of the Project 3 2005 Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2005 Bonds and the Columbia 2005 Bonds. No Bondholder has a claim on the assets of any Project.

The 2005 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 2005 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 2005 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 2005 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 2005 Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the 2005 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 2005 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 2005 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 2005 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 which is to be paid from the proceeds of the Series 2005-A Bonds and the Series 2005-B (Taxable) Bonds and similar notes to be issued pursuant to credit agreements to be executed in 2005 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 2005 Bonds, pursuant to Separate Subordinated Resolutions, other than 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 Net Billed Project capability 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 AMENDED FISCAL YEAR 2005 BUDGETS" for a list of Participants and their respective shares of the Projects' Fiscal Year 2005 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.

All payments required to be made by Bonneville under the Net Billing Agreements, the Assignment Agreements and the 1989 Letter Agreement 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, respectively (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 behalves. 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 otherwise. In the event that it is 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."

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 2004 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, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury.

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."

BOND INSURANCE

Concurrently with the issuance of the of the 2005 Bonds, Ambac Assurance Corporation ("Ambac") will issue its Financial Guaranty Insurance Policy for the Project 1 2005-A Bonds in the aggregate principal amount of $72,175,000 due July 1, 2013 through July 1, 2015, the Columbia 2005-A Bonds in the aggregate principal amount of $65,965,000 due on July 1, 2016 and July 1, 2018, the Project 3 2005-A Bonds in the aggregate principal amount of $83,200,000 due on July 1, 2013 and July 1, 2015, the Project 1 2005-B (Taxable) Bonds in the aggregate principal amount of $925,000 due on July 1, 2008, the Columbia 2005-B (Taxable) Bonds in the aggregate principal amount of $1,600,000 due on July 1, 2008 and the Project 3 2005-B (Taxable) Bonds in the aggregate principal amount of $1,060,000 due on July 1, 2008. The 2005 Bonds so insured are herein referred to as the "Insured Bonds."

The following information has been furnished by Ambac for use in this Official Statement. Reference is made to Appendix K for a specimen of Ambac's policy.

Payment Pursuant to Financial Guaranty Insurance Policy

Ambac Assurance has made a commitment to issue a financial guaranty insurance policy (the "Financial Guaranty Insurance Policy") relating to the Insured Bonds effective as of the date of issuance of the Insured Bonds. Under the terms of the Financial Guaranty Insurance Policy, Ambac Assurance will pay to The Bank of New York, in New York, New York or any successor thereto (the "Insurance Trustee") that portion of the principal of and interest on the Insured Bonds which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor (as such terms are defined in the Financial Guaranty Insurance Policy). Ambac Assurance will make such payments to the Insurance Trustee on the later of the date on which such principal and interest becomes Due for Payment or within one business day following the date on which Ambac Assurance shall have received written notice of Nonpayment from the Trustee. The insurance will extend for the term of the Insured Bonds and, once issued, cannot be canceled by Ambac Assurance.

The Financial Guaranty Insurance Policy will insure payment only on stated maturity dates and on mandatory sinking fund redemption dates, in the case of principal, and on stated dates for payment, in the case of interest. If the Insured Bonds become subject to mandatory redemption and insufficient funds are available for redemption of all outstanding Insured Bonds, Ambac Assurance will remain obligated to pay principal of and interest on outstanding Insured Bonds on the originally scheduled interest and principal payment dates including mandatory sinking fund redemption dates. In the event of any acceleration of the principal of the Insured Bonds, the insured payments will be made at such times and in such amounts as would have been made had there not been an acceleration.

In the event the Trustee has notice that any payment of principal of or interest on an Insured Bond which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from its registered owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such registered owner will be entitled to payment from Ambac Assurance to the extent of such recovery if sufficient funds are not otherwise available.

The Financial Guaranty Insurance Policy does **not** insure any risk other than Nonpayment, as defined in the Policy. Specifically, the Financial Guaranty Insurance Policy does **not** cover:

1. payment on acceleration, as a result of a call for redemption (other than mandatory sinking fund redemption) or as a result of any other advancement of maturity.

2. payment of any redemption, prepayment or acceleration premium.

3. nonpayment of principal or interest caused by the insolvency or negligence of any Trustee, Paying Agent or Bond Registrar, if any.

If it becomes necessary to call upon the Financial Guaranty Insurance Policy, payment of principal requires surrender of Insured Bonds to the Insurance Trustee together with an appropriate instrument of assignment so as to permit ownership of such Insured Bonds to be registered in the name of Ambac Assurance to the extent of the payment under the Financial Guaranty Insurance Policy. Payment of interest pursuant to the Financial Guaranty Insurance Policy requires proof of Holder entitlement to interest payments and an appropriate assignment of the Holder's right to payment to Ambac Assurance.

Upon payment of the insurance benefits, Ambac Assurance will become the owner of the Insured Bond, appurtenant coupon, if any, or right to payment of principal or interest on such Insured Bond and will be fully subrogated to the surrendering Holder's rights to payment.

Ambac Assurance Corporation

Ambac Assurance Corporation ("Ambac Assurance") is a Wisconsin-domiciled stock insurance corporation regulated by the Office of the Commissioner of Insurance of the State of Wisconsin and licensed to do business in 50 states, the District of Columbia, the Territory of Guam, the Commonwealth of Puerto Rico and the U.S. Virgin Islands, with admitted assets of approximately $8,329,000,000 (unaudited) and statutory capital of $5,224,000,000 (unaudited) as of December 31, 2004. Statutory capital consists of Ambac Assurance's policyholders' surplus and statutory contingency reserve. Standard & Poor's Credit Markets Services, a Division of The McGraw-Hill Companies, Moody's Investors Service and Fitch Ratings have each assigned a triple-A financial strength rating to Ambac Assurance.

Ambac Assurance has obtained a ruling from the Internal Revenue Service to the effect that the insuring of an obligation by Ambac Assurance will not affect the treatment for federal income tax purposes of interest on such obligation and that insurance proceeds representing maturing interest paid by Ambac Assurance under policy provisions substantially identical to those contained in its financial guaranty insurance policy shall be treated for federal income tax purposes in the same manner as if such payments were made by the Obligor of the Insured Bonds.

Ambac Assurance makes no representation regarding the 2005 Bonds or the advisability of investing in the 2005 Bonds and makes no representation regarding, nor has it participated in the preparation of, this Official Statement other than the information supplied by Ambac Assurance and presented under the heading "SECURITY FOR THE NET BILLED BONDS — BOND INSURANCE."

Available Information

The parent company of Ambac Assurance, Ambac Financial Group, Inc. (the "Company"), is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and in accordance therewith files reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC"). These reports, proxy statements and other information can be read and copied at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. The SEC maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding companies that file electronically with the SEC, including the Company. These reports, proxy statements and other information can also be read at the offices of the New York Stock Exchange, Inc. (the "NYSE"), 20 Broad Street, New York, New York 10005.

Copies of Ambac Assurance's financial statements prepared in accordance with statutory accounting standards are available from Ambac Assurance. The address of Ambac Assurance's administrative offices and its telephone number are One State Street Plaza, 19th Floor, New York, New York, 10004 and (212) 668-0340.

Incorporation of Certain Documents by Reference

The following documents filed by the Company with the SEC (File No. 1-10777) are incorporated by reference in this Official Statement:

1. The Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004 and filed on March 15, 2005;
2. The Company's Current Report on Form 8-K dated April 5, 2005 and filed on April 11, 2005;
3. The Company's Current Report on Form 8-K dated and filed on April 20, 2005; and
4. The Company's Current Report on Form 8-K dated May 3, 2005 and filed on May 5, 2005.
5. The Company's Quarterly Report on Form 10-Q for the fiscal quarterly period ended March 31, 2005 and filed on May 10, 2005.

All documents subsequently filed by the Company pursuant to the requirements of the Exchange Act after the date of this Official Statement will be available for inspection in the same manner as described above in "Available Information."

Rights of Ambac

Notwithstanding anything in the Resolutions to the contrary and in addition to the provisions of the Resolutions relating to control of proceedings in the case of an Event of Default, so long as the Bond Insurance Policy is then in effect and Ambac has not failed or refused to perform its obligations with respect to the Bond Insurance Policy, upon the occurrence and continuance of an Event of Default as defined in the Resolutions, Ambac shall be entitled to control and direct the enforcement of all rights and remedies granted to the Owners of the Insured Bonds or to the Trustee for the benefit of such Owners under the Resolutions. Whether or not an Event of Default has occurred and is continuing, so long as the Bond Insurance Policy is then in effect and Ambac has not failed or refused to perform its obligations with respect to the Bond Insurance Policy, the Resolutions provide that Ambac is deemed to be the Owner of all Insured Bonds for purposes of (a) initiating any action or effecting any demand that such Owners may initiate or effect and (b) approving or disapproving any action, forbearance or amendment that is subject to Owner approval.

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 which 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, 2004" 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, 2004.

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 April 1, 2005. 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 APRIL 1, 2005

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Prior Lien Refunding Revenue Bonds	$ 892,890,000
Electric Revenue Refunding Bonds	1,084,435,000
TOTAL PROJECT 1	$ 1,977,325,000
COLUMBIA:	
Prior Lien Refunding Revenue Bonds	$ 885,990,000
Electric Revenue Refunding Bonds	1,206,115,000
Electric Revenue Bonds	67,950,000
TOTAL COLUMBIA	$ 2,160,055,000
PROJECT 3:	
Prior Lien Refunding Revenue Bonds	$ 874,470,000
Electric Revenue Refunding Bonds	1,060,320,000
TOTAL PROJECT 3	$ 1,934,790,000
TOTAL NET BILLED REVENUE BONDS	$ 6,072,170,000
Packwood Revenue Bonds (2)	$ 3,751,000
Nine Canyon Wind Project Revenue Bonds (2)	$ 92,635,000

(1) Includes $48,127,000 accreted value of Compound Interest Bonds for Columbia and $347,965,000 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 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
Amy C. Solomon, Assistant Secretary	Program Officer	June 2005
Tom Casey	Public Utility District Commissioner	June 2006
Vera Claussen	Public Utility District Commissioner	June 2006
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
Tim Sheldon	Washington State Senator	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	34 years
Dale K. Atkinson	Vice President, Nuclear Generation	27 years
W. Scott Oxenford	Vice President, Technical Services	21 years
John W. Baker	Vice President, Energy/Business Services/Public Information Officer	33 years
Albert E. Mouncer	Vice President, Corporate Services/General Counsel/Chief Financial Officer	24 years
Cheryl M. Whitcomb	Vice President, Organizational Performance and Staffing/Chief Knowledge Officer	30 years

EMPLOYEES

Energy Northwest currently employs approximately 1,208 employees. Of these employees, 336 are members of the International Brotherhood of Electrical Workers ("IBEW"), 114 are members of the Paper, Allied Industrial, Chemical & Energy Workers ("PACE") 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 PACE 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 and HAMTC collective bargaining agreements expire in 2007. The PACE collective bargaining agreement expired on November 2, 2002. Negotiations continue for a new agreement for the PACE bargaining unit. Washington State law provides for binding interest arbitration for the PACE collective bargaining unit. 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. 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 an amended maintenance, operating, outage, fuel and capital budget for Columbia of $259 million for the 2005 fiscal year, which ends on June 30, 2005.

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 projected at $32.70 per megawatt-hour for the 2005 fiscal year. This cost is higher than the $21.85 per megawatt-hour for the 2004 fiscal year because the 2005 fiscal year projections include a refueling outage as well as a forced outage. 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 reactor has been continuously on line since restart on August 22, 2004. The next scheduled outage will be in May 2005. Energy Northwest continues to place a high priority on cost-containment. Measures have been implemented to keep costs within the original fiscal year 2005 budget despite the costs of the forced outage.

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.

While Energy Northwest intends to operate Columbia a greater percentage of the time, Energy Northwest has also evaluated plans to increase the gross capacity of the plant. Engineers evaluated a proposal that could increase the plant's name plate capacity to about 1,350 megawatts - a 12.5% increase in power. Based on current market conditions and other technical considerations, this effort has been put on hold. 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 will be working 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 25 such requests since 2000. The Executive Board will determine whether to apply for an extension.

Energy Northwest also has pursued several other ventures beyond the operation of Columbia - all of which are designed to relieve, in part, fixed-cost pressures on Columbia. Contracts to outsource engineering and testing services have allowed Energy Northwest to better use resources originally dedicated to Columbia.

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 68.4% and has generated 132,678,548 megawatt hours (net of station use) of electric power through January 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, 2003 and 2004 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 2003	FY 2004
Operations, Maintenance and Overhead	$159,312	$151,181
Nuclear Fuel Burnup	27,061	35,322
Spent Fuel Disposal Fee	7,253	9,029
Generation Taxes	2,237	3,199
Decommissioning	26,505	42,993
Depreciation and Amortization	79,528	79,932
Investment Income	(6,751)	(1,878)
Interest Expense and Discount Amortization	119,666	119,604
Other Expense/(Revenue)	(1,765)	(1,967)
Total Costs	$413,046	$437,415
Net Generation (Million kWhs) (unaudited)	7,738(2)(3)	9,520(2)(3)

(1) Amounts derived from audited Energy Northwest financial statements.
(2) Includes credit for "Economic Dispatch" of 16 million kWhs and 121 million kWhs for fiscal years 2004 and 2003, respectively. Total energy not generated due to reductions requested by Bonneville is referred to by Bonneville as "Economic Dispatch."
(3) The increase in generation was the result of the station running the entire year after the completion of its 2-year refueling and maintenance outage at the end of fiscal year 2003.

Capital Improvements

Energy Northwest has been making capital improvements to Columbia since it began commercial operation. In fiscal year 2004, the cash spent on capital improvements was $30.5 million. These capital improvements included heightened security improvements mandated by the Nuclear Regulatory Commission (the "NRC"), the Hydrogen Water Chemistry Injection Project being implemented to mitigate cracking of welds and components in the reactor vessel and upgrading the security system computer.

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. Columbia had a green finding in February 2005. There have been no findings other than green 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 Fourth Quarter 2004 Regulatory Oversight Process Summary lists 78 plants, including Columbia, in the Licensee Response Column, 21 plants in the Regulatory Response Column and three plants in 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.

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 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 now 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 Framatome ANP, Inc. 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 2008.

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 ($9.0 million for the 12 months ended June 30, 2004). 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 have 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 $630 million (in 2004 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 ("EFSEC"). Energy Northwest's estimate of Columbia's site restoration costs is approximately $80 million (in 2004 dollars).

The current funding plan requires annual deposits 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, 2004, totaled approximately $89.4 million. A separate fund has been established for site restoration. The balance of this fund as of December 31, 2004, totaled approximately $10.4 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 $10.4 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 $10.86 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 $10 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 $2.25 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 nameplate 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.

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. As of November 2002, the power produced is being sold directly to two of those participants, Benton County PUD and Franklin County PUD. The one year agreements with Benton County PUD and Franklin County PUD expire in September 2005.

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, including Energy Northwest, which has acquired a portion of the capability for station use by Columbia. 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 to be billed to the purchasers are expected to be in the range of 3.5 cents per kilowatt hour to 3.9 cents per kilowatt hour during the first five fiscal years of operation and the cost allocable to Energy Northwest would constitute an operating expense of Columbia.

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.

Site restoration requirements for Project 1 (as well as Project 4) are governed by a site certification agreement between Energy Northwest and the State of Washington and regulations adopted by EFSEC and a lease agreement with DOE.

Energy Northwest, Bonneville, EFSEC and DOE executed an agreement concerning site restoration of Projects 1 and 4 in December 2003. The agreement provides that final remediation may be deferred up to 23 years and completion of final remediation within about three years after the end of the deferral period. Near term remediation is to be completed within two years to implement specified health, safety, and environmental protection cleanup activities. This near term work scope is currently estimated to cost $4 million and is scheduled for completion in 2005.

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. Bonneville's site remediation obligation, even if reuse of the sites and structures does not occur, is not conditioned on the adequacy of funds in the trust account.

In January 2004, Energy Northwest adopted a policy statement for the potential reuse of Projects 1 and 4. This policy provides for the continued safe, environmentally sound, and cost efficient operation of the Columbia Generating Station in the best interests of Energy Northwest, Bonneville, public power, and the region's ratepayers. Any proposed uses, whether public or private, will be subject to contributing to the goals of assuring public health and safety, reducing Columbia's cost of power, reducing Projects 1 and 4 costs, and providing for local economic development.

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. Subsequent to 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.

HANFORD GENERATING PROJECT

The Hanford Generating Project ("HGP") owned by Energy Northwest ceased operation in 1987, and site restoration activities coordinated with the DOE were completed in 2004.

RESOURCE DEVELOPMENT

Several years 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, the Net Billing Agreements or Projects 1, 3 and Columbia.

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:

<u>DuraBrake Company v. Energy Northwest</u>. 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. 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.

<u>Washington State Department of Revenue and General Electric.</u> 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.

<u>Energy Northwest v. United States of America</u>. 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 Generating Station 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. This matter is not currently set for trial and 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 2005 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 2005-A Bonds from the gross income of the owner 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 which 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

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 2005-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 2005-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 2005-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."

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, interest on the Series 2005-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. 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 2005-B Bonds.

To the extent the issue price of any maturity of the Series 2005-A Bonds is less than the amount to be paid at maturity of such Series 2005-A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2005-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 2005-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 2005-A Bonds is the first price at which a substantial amount of such maturity of the Series 2005-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 2005-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 2005-A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2005-A Bonds. Beneficial Owners of the Series 2005-A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2005-A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2005-A Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2005-A Bonds is sold to the public.

Series 2005-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 2005-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 2005-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 2005-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 2005-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 2005-A Bonds, and other relevant documents may be changed and certain actions (including without limitation defeasance of the 2005-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 2005-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 2005-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 2005-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 or the 1954 Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville have covenanted, however, to comply with the 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 2005-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 2005-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 2005 Bonds ends with the issuance of the 2005 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 2005-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 2005-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 2005 Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

RATINGS

Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc. ("S&P"), Moody's Investors Service ("Moody's") and Fitch, Inc. ("Fitch") have assigned the uninsured 2005 Bonds the ratings of AA-, Aaa and AA-, respectively. S&P, Moody's and Fitch have assigned the Insured Bonds the ratings of AAA, Aaa and AAA, respectively, with the understanding that upon delivery of the Insured Bonds, a policy insuring the payment when due of principal of and interest on the Insured Bonds will be issued by Ambac Assurance Corporation. 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 2005 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 2005 Bonds.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2005 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 is $1,660,824. The Underwriters' obligations are subject to certain conditions precedent contained in the bond purchase contract and they will be obligated to purchase all of the 2005 Bonds if any such 2005 Bonds are purchased. The 2005 Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such 2005 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 2005 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 2005 Bonds, for the benefit of the owners and beneficial owners of the 2005 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 2005 Bonds, if material. Energy Northwest Annual Information is to be provided not later than December 31 of each year, commencing December 31, 2005. The Bonneville Annual Information is to be provided not later than March 31 of each year, commencing March 31, 2006. The Annual Information will be filed with each Nationally Recognized Municipal Securities Information Repository (the "NRMSIRs") and with the State Depository for the State of Washington, if such State Depository exists (the "State Depository") (or provided to a transmitting entity approved by the SEC). At this time, there is no State Depository. 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 2005 Bonds, the basic agreements securing the 2005 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 2005 Bonds is to be construed as a contract with the holders of such Series of 2005 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

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest ("Energy Northwest" or, the "Issuer") by Bonneville for use in the Official Statement, dated May 19, 2005, furnished by the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2005-A, Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A, Project 3 Electric Revenue Refunding Bonds, Series 2005-A, Project 1 Electric Revenue Refunding Bonds, Series 2005-B (Taxable), Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable), and, Project 3 Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (collectively, the "Series 2005 Bonds"). 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 2005 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 30 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 ("Bureau"). These projects have an expected aggregate output of roughly 9,000 average megawatts under median water conditions. Bonneville also has acquired and markets power from several non-federally owned and operated projects, including the Columbia Generating Station, an operating nuclear generating station owned by Energy Northwest and having a rated capacity of approximately 1150 megawatts. Bonneville sells, purchases and exchanges firm power, non-firm energy, peaking capacity and related power services. Bonneville also constructed and operates and maintains a high voltage transmission system comprising approximately 75% of the bulk transmission capacity in the Pacific Northwest. Bonneville uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities and power marketers.

Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, 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 45% of the electric power consumed within the Region. Bonneville markets the majority of this power to over 100 publicly-owned and cooperatively-owned utilities ("Preference Customers") for resale to consumers in the Region. Bonneville also has contracts to sell power for direct consumption to a small number of companies ("Direct Service Industries" or "DSIs") located in the Region, although the contracted amount of service Bonneville provides to DSIs has diminished substantially relative to 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 historically have been 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 annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayments of appropriated amounts to the Corps and the Bureau for certain costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2004 payment responsibility to the United States Treasury of $1.053 billion (including $346 million in principal payments in advance of due dates under the Debt Optimization Proposal as described in this Appendix A) in full and on time. 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 Proposal."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements (described in the Official Statement), and cash payments, if any, under the 1989 Letter Agreement (described in the Official Statement), 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 if any under Net Billing Agreements and cash payments, if any, under the 1989 Letter Agreement, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See 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 prices but declined in fiscal year 2002. Prices have since 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.

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

At or slightly before the end of Bonneville's fiscal year 2001, which ended on September 30, 2001, all of Bonneville's then existing long-term, in-Region power sales contracts with Preference Customers, 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 new long-term power sales and related agreements for the period beginning on or slightly before October 1, 2001. Under this "Subscription Strategy," Bonneville entered into five- and ten-year power sales contracts with 127 Regional Preference Customers, into ten-year power sales contracts with eight Federal agencies, and into five-year power sales contracts with a small number of DSI companies. Bonneville also entered into settlement contracts with all six of the Regional IOUs to settle Bonneville's obligations under the Residential Exchange Program through fiscal year 2011.

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

In view of the foregoing Augmentation Purchases and load reduction agreements, lowered expectations regarding Regional load growth, and diminished expectations that aluminum company DSIs will meet their power purchase obligations, Bonneville believes that it may have a relatively modest amount of firm power in excess of actual firm loads in fiscal year 2006 and may have some market price risk in making discretionary power sales of that excess firm power. In fiscal year 2005, water conditions are substantially below average and, depending on runoff and precipitation conditions, loads and other factors in the remainder of operating year 2005, it is possible that Bonneville may have to make power purchases to meet contracted loads in such year.

In fiscal years 2000-2001, coincident with the development of the power sales and related contracts under the Subscription Strategy, Bonneville developed and proposed power rates for such Subscription agreements for the five-year period beginning October 1, 2001 (the "2002 Final Power Rates"). The 2002 Final Power Rates are comprised of "base rates" and certain rate level adjustment mechanisms. FERC approved the proposed 2002 Final Power Rates, including the base rates and the rate level adjustment mechanisms, on July 21, 2003.

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

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

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

Under the third rate adjustment mechanism, the Safety Net Cost Recovery Adjustment Clause ("SN-CRAC"), Bonneville reserved the ability to impose one or more separate rate level increases in order to recover costs on a temporary basis if certain conditions indicating that Bonneville is not adequately recovering its costs are met. In early calendar year 2003, Bonneville determined that the conditions triggering an SN-CRAC proceeding had been met and later developed and formally proposed a specific SN-CRAC rate level adjustment to be effective for fiscal years 2004 through 2006 (the "2004 SN-CRAC Rate Level Adjustment"). Under the 2004 SN-CRAC Rate Level Adjustment, related power rate levels are adjusted for a fiscal year primarily on the basis of the Power Business Line's third quarter projected net revenues for the respective prior fiscal year. Certain costs in a number of major cost categories are capped and are not automatically recovered through the 2004 SN-CRAC Rate Level Adjustment. The maximum revenue recoverable through the 2004 SN-CRAC Rate Level Adjustment through fiscal year 2006 is capped at $290 million per year.

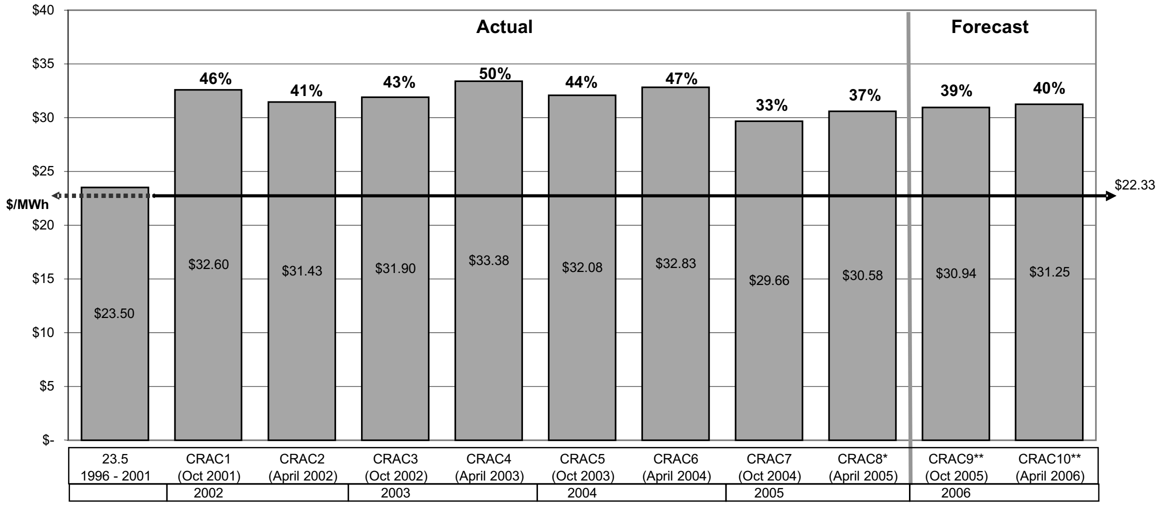
The following Table depicts the cumulative effects of the base rate and the three rate adjustment mechanisms on Bonneville's average Subscription power rate levels for full requirements service at Bonneville's Priority Firm ("PF") power rate on both a historical and forecast basis. See "POWER BUSINESS LINE—Customers and Other Power Contract Parties of Bonneville's Power Business Line."

With respect to fiscal year 2005 rate levels, the following table reflects the effects of certain rate level determinations to be in effect in such year, made by Bonneville in September 2004. On September 16, 2004, Bonneville set the FB-CRAC and SN-CRAC rate level adjustments to be in effect in fiscal year 2005. For fiscal year 2005 the SN-CRAC rate level adjustment was set at zero percent of base power rates for Subscription power sales. By contrast, the SN-CRAC rate level adjustment in effect in fiscal year 2004 was set at about 10 percent of such base rates. The fiscal year 2005 FB-CRAC rate level adjustment was set at its maximum of roughly 11 percent of base power rates, which is about the same as is in effect in fiscal year 2004.

After taking into account the base power rates and the effects of the FB-CRAC, SN-CRAC and LB-CRAC rate level adjustments, Bonneville now expects that average rate levels in effect in fiscal year 2005 for Subscription power sales will be approximately $30-$31 per megawatt hour, depending on type of service and excluding transmission. By contrast, such rates were slightly below $33 per megawatt hour in the last six months of fiscal year 2004, depending on type of service and excluding transmission. Bonneville's power rate levels increased slightly for the six month period beginning April 1, 2005, reflecting increases in the LB-CRAC rate level adjustment for such period. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001—Residential Exchange Program Obligations" herein.

The power rates portrayed below do not include requirements service provided to certain small Preference Customers who committed to purchase power from Bonneville early in the Subscription process at power rates that are not subject to the cost recovery adjustment mechanisms. The depiction below portrays only full requirements service offered under Bonneville's Subscription power rates schedules and does not portray rate levels related to Slice of the System, Partial Requirements, DSI and Regional IOU Exchange Settlements. Nonetheless, Bonneville believes it illustrates the impacts of the rate adjustments in the current rate period and provides a basis to compare Subscription power rates with rate levels in the prior rate period.

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



*Each bar represents the average full requirements rate levels for the indicated period, taking into account the LB-CRAC, FB-CRAC and SN- CRAC adjustments. The percentage above each bar is the percentage of Base Rate levels by which the CRAC adjusted rate levels exceed such Base Rate levels. The forecasted rate levels are as of December 17, 2004, and are subject to change. See "Subscription Power Rates."

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In developing the 2004 SN-CRAC Rate Level Adjustment proposal, Bonneville estimated that it would provide Bonneville with an 80 percent or better probability of meeting Bonneville's payment responsibility to the United States Treasury in full and on time over the three fiscal years beginning October 1, 2003. Such estimates were based on a number of forecasts and assumptions.

Under current internal forecasts of future market prices, Bonneville believes that its Subscription power rates levels, as adjusted by the various rate level adjustment mechanisms, on average in fiscal years 2005-2006 will remain below market prices for such period based on similar power products. Bonneville believes that its Subscription power rates will not exceed the cost of new natural gas fired generation when shaped to serve loads similar to the shaping ability of the Federal System. Such belief is based on market, rate and other forecasts that are subject to many variables most of which are not within Bonneville's control. For a more detailed description of Bonneville's proposal for power rates applicable to Subscription power sales, see "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates."

FERC has approved the 2002 Final Power Rates and the 2004 SN-CRAC Rate Level Adjustment. The approvals 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."

In addition, several of Bonneville's customers and customer groups filed separate suits in the Ninth Circuit Court challenging Bonneville's decision that the conditions specified in the 2002 Final Power Rates enabling Bonneville to initiate the proceedings necessary for implementing the SN-CRAC by developing an 2004 SN-CRAC Rate Level

Adjustment had been met. See "BONNEVILLE LITIGATION—Industrial Customers of the Northwest Utilities, et al. v. Bonneville Power Administration."

Bonneville believes that its ability to recover power costs during the remaining term of the five-year rate period ending September 30, 2006 is and will be a function of several key risks: (i) the level and volatility of market prices for electric power in western North America, which define the revenues Bonneville receives from discretionary sales of energy; (ii) the level of Bonneville's load serving obligation after voluntary load reductions and negotiated power buy-backs; (iii) water conditions in the Columbia River drainage, which determine the amount of power Bonneville has to sell and its economic value and the amount of power it has to purchase in order to meet its commitments; (iv) changes in fish protection requirements, which could be the source of substantial additional expense to Bonneville and could further affect the amount and value of hydroelectric energy produced by the Federal System; and (v) operating costs, generally.

Bonneville's Fiscal Year 2004 Financial Results

As set forth in Bonneville's audited financial statements for the fiscal year ended September 30, 2004 ("Fiscal Year 2004"), Bonneville made payments to the United States Treasury of $1.053 billion. These payments were made in accordance with Bonneville's scheduled United States Treasury repayment responsibilities and $346 million in advance amortization of debt under the Debt Optimization Proposal. For a description of the Debt Optimization Proposal, see "BONNEVILLE FINANCIAL OPERATIONS—Debt Optimization Proposal." Bonneville also recorded net revenues of approximately $504 million, although absent the net revenue effects of the Debt Optimization Proposal and other debt management actions relating to Energy Northwest, Bonneville had net revenues of about $66 million. The fiscal year end net revenue amount of $66 million also excludes $89 million in unrealized mark-to-market gains under the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard No. 133 ("SFAS 133"). By way of contrast to fiscal year 2004, in fiscal year 2003, Bonneville made payments to the United States Treasury in the amount of $1.057 billion. This amount included $315 million in advance amortization of debt under the Debt Optimization Proposal. In addition, in fiscal year 2003, Bonneville recorded net revenues of about $37 million after excluding the positive net revenue effects of such advance amortization and the unrealized mark-to-market gains under SFAS 133.

A number of elements contributed to Bonneville's financial performance in fiscal year 2004. Runoff conditions in Operating Year 2004 (July 30, 2003 to August 1, 2004) were about 77 percent of average, representing the fifth consecutive year of below average runoff conditions in the Region. These lower than average runoff conditions led to reduced amounts of discretionary power sales from hydroelectric generation, and somewhat lower amounts of such sales, when compared to fiscal year 2003 when runoff conditions were about 85 percent of average. Several factors partially offset the financial effects of lower than average runoff conditions. First, while amounts received by Bonneville under the LB-CRAC rate level adjustment continued to decline with a decline in the costs of Augmentation Purchases and related actions, Bonneville received enhanced revenues of about $83.5 million under the first year of the 2004 SN-CRAC Rate Level Adjustment. Second, Bonneville once again triggered the application of the FB-CRAC rate level adjustment for all of fiscal year 2004, receiving revenue in amounts roughly equivalent to those resulting from the LB-CRAC in fiscal year 2003. The FB-CRAC rate level adjustment allowed Bonneville to recover about $102 million in additional revenues in fiscal year 2004, after taking into account certain effects related to the Slice of the System contracts described in this Appendix A. See "POWER BUSINESS LINE—Certain Statutes and other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001." Third, in fiscal year 2004, Bonneville received a total of about $77 million of United States Treasury repayment credits, most of which are derived under section 4(h)(10)(C) of the Northwest Power Act. These credits are provided to reimburse Bonneville for certain fish and wildlife costs incurred by Bonneville, including power purchases made by Bonneville that are attributable to the effects of operating the hydroelectric system for the benefit of fish. 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." Fourth, net interest expense borne by Bonneville declined by about $61 million (or, 18 percent), in each case when compared to fiscal year 2003.

In addition, Bonneville closed fiscal year 2004 with $638 million in fiscal year-end financial reserves as compared to $511 million at the end of fiscal year 2003 and $188 million at the end of fiscal year 2002. Bonneville's financial reserves include cash and "deferred borrowing." Deferred borrowing represents amounts that Bonneville is authorized to borrow from the United States Treasury for expenditures that Bonneville has incurred to date but the borrowing for which Bonneville has elected to delay. Several primary reasons contributed to the fiscal year 2004 increase in year-end reserves despite modest adjusted net revenues and low runoff conditions. First, revenues in cash to Bonneville at the end of fiscal year 2004 were relatively greater because net billing of Energy Northwest's budgeted costs for its fiscal year 2005 (which began on July 1, 2004) was fulfilled much earlier in Energy Northwest's fiscal year than had been the case in the past. This resulted in Bonneville's receiving comparatively greater cash payments from Energy Northwest Net Billing Participants in the later portion of Bonneville's fiscal year 2004, which led to higher fiscal year end financial reserves at the end of Bonneville's fiscal year 2004. Second, Bonneville obtained higher than forecasted prices for discretionary power sales. Third, Bonneville had higher than forecasted earnings on reserves in the Bonneville Fund. Fourth, fiscal year end financial reserves reflected about $62 million in funds held in the Bonneville Fund at the end of the fiscal year for other Federal agencies in connection with conservation efficiency programs Bonneville is assisting in and about $28 million in construction payments received by Bonneville for certain transmission facilities owned by others. Such amounts are typically held by Bonneville for short periods. For a discussion of year-to-year financial results see "BONNEVILLE FINANCIAL OPERATIONS—Management Discussion of Operating Results."

Fiscal Year 2005 Developments

Unaudited Quarterly Report for the Six Months Ended March 31, 2005.

Bonneville's unaudited quarterly report for the six month period ended March 31, 2005 ("Fiscal Year 2005 Second Quarter") indicates that Bonneville's net revenues for such period decreased to $238 million from $347 million when compared to the same six month period in fiscal year 2004 ("Fiscal Year 2004 Second Quarter"). Fiscal Year 2005 Second Quarter total operating revenues declined about $18 million when compared to Fiscal Year 2004 Second Quarter, reflecting, in large part, a $22 million decline in unrealized SFAS 133 mark-to-market gains on power transactions. For a discussion of SFAS 133, see "—Bonneville's Fiscal Year 2004 Financial Results." Operating expenses for Fiscal Year 2005 Second Quarter increased by about $99 million (or 9 percent) when compared to Fiscal Year 2004 Second Quarter. Operations and maintenance increased by $77 million (or 15 percent) and non-federal project expense increased by about $31 million, in each case when compared to Fiscal Year 2004 Second Quarter. The comparative increase in such operating expenses was caused in part by a $28 million increase in non-federal projects' operation and maintenance expense, including fuel purchases, for the Columbia Generating Station, and a $13 million increase in fish and wildlife operations and maintenance expense borne by Bonneville. In addition, debt service for non-federal projects increased by about $31 million (or 24 percent). This change in debt service for non-federal projects reflects that such expenses were inordinately low in fiscal year 2004 because debt service reserve funds at Energy Northwest were used to fund Energy Northwest debt service in such fiscal year when the reserve funds were replaced with surety bonds. These comparative increases in operating expenses were offset to a degree by a decline in purchase power expense of about $13 million (or 4 percent) and a decline in net interest expense of $8 million (or 5 percent), reflecting a decline in the average weighted interest on bonds issued by Bonneville to the United States Treasury and somewhat greater earnings on cash balances in the Bonneville Fund. For further information regarding Fiscal Year 2005 Second Quarter unaudited results, see Appendix B-2.

Year End Financial Forecast for Fiscal Year 2005.

Current analyses prepared outside of Bonneville, but relied on by Bonneville, indicate that streamflow and snowpack conditions in the Columbia River basin are and will continue to be below average in operating year 2005 (ending August 1, 2005). The analyses indicate that, based on current dry conditions in the basin, runoff may be between 65 percent and 71 percent of average in operating year 2005 (ending August 1, 2005). The low water conditions are expected to result in diminished amounts of discretionary power sales and diminished revenues therefrom in fiscal year 2005.

With the current year being the sixth consecutive year of lower than average Pacific Northwest precipitation, hydro conditions are such that Bonneville expects that it may have to make some power purchases in fiscal year 2005 to meet loads. Low water conditions are also expected to reduce surplus power sales revenues for the fiscal year from what Bonneville had expected in setting the 2004 SN-CRAC Rate Level Adjustment for fiscal year 2005. If Bonneville were to have to make substantial power purchases at the high power prices currently prevailing in the market, Bonneville's financial condition in fiscal year 2005 could be adversely affected. Notwithstanding the foregoing, Bonneville is managing its exposure to market purchases and expects that it will meet its fiscal year 2005 United States Treasury repayment obligation on time and in full. The amounts and prices of power purchases could affect whether and the extent to which Bonneville would use the 2004 SN-CRAC Rate Level Adjustment to increase power revenues in fiscal year 2006 to cover any revenue shortfalls from market purchases and reduced secondary energy sales in fiscal year 2005.

Near the end of August 2005, Bonneville will determine whether and the extent to which it will employ the 2004 SN-CRAC Rate Level Adjustment and FB-CRAC in fiscal year 2006. The determinations will depend in substantial part on then-projected year-end financial reserve forecasts for fiscal year 2005. Since Bonneville is unable to ascertain fiscal year 2005 year-end financial reserves and numerous other factors that would be considered in such determinations, Bonneville is unable to predict with certainty the rate effects of the 2004 SN-CRAC Rate Level Adjustment and FB-CRAC in fiscal year 2006. Bonneville's preliminary projections are that a fully implemented 2004 SN-CRAC Rate

Level Adjustment would, if necessary, increase revenues by roughly $290 million in aggregate in fiscal year 2006. Bonneville expects that a fully implemented FB-CRAC will be employed in fiscal year 2006, and will yield about $115 million in such year, which is slightly more than was obtained under the FB-CRAC in fiscal year 2004.

President's Fiscal Year 2006 Budget.

The President's Fiscal Year 2006 Budget includes a proposal for legislation that calls "for certain nontraditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville's] statutory debt limit." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Nonetheless, the budget provides that the proposal would only affect those transactions occurring after enactment of the legislation. In addition, the Department of Energy has agreed that the proposed legislation will not affect Bonneville's ability to participate in the refinancing of debt it secures pursuant to transactions that Bonneville entered into prior to the date the proposed legislation takes effect.

The President's Fiscal Year 2006 Budget also includes a proposal for legislation "to very gradually bring [the federal power marketing administrations', including Bonneville's] electricity rates closer to average market rates throughout the country." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Bonneville is unable to predict whether such legislation will be introduced in, or enacted into law by, Congress. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Proposals for Federal Legislation and Administrative Action Relating to Bonneville."

Power Marketing After Fiscal Year 2006

Bonneville currently has about 1000 average megawatts of Augmentation Purchases, which will decline to about 800 average megawatts by fiscal year 2006 before expiring at or near the end of fiscal year 2006. In addition, all of the remaining contractually-committed, take-or-pay power purchases by aluminum company DSIs will expire at the end of fiscal year 2006. (As part of the Subscription process, Bonneville had originally agreed to sell in aggregate to such DSIs about 1500 average megawatts of power for the five years ending September 30, 2006. Bonneville is currently selling only about 200-300 average megawatts to DSIs because of contract amendments and suspensions and DSI bankruptcies and insolvencies.)

Moreover, in developing the Subscription Strategy in calendar years 1999-2001, Bonneville assumed that it would meet through physical power sales about 2200 average megawatts of Regional IOU residential and small farm loads after fiscal year 2006 under certain settlements that Bonneville entered into with the six Regional IOUs with respect to the Residential Exchange Program. As provided in such settlements (the "Residential Exchange Settlement Agreements"), Bonneville has exercised certain contract rights to meet its Residential Exchange Settlement Agreement obligations through the payment of monetary benefits rather than through physical sales of power to Regional IOUs after fiscal year 2006. The Residential Exchange Settlement Agreements and the related agreements under which Bonneville exercised the right to provide only monetary benefits thereunder after fiscal year 2006 are currently being challenged in litigation. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

Finally, while a large portion of the existing Regional Preference Customer Subscription power sales contracts are in effect through fiscal year 2011, about 800 average megawatts of such loads are under contract only through fiscal year 2006. Bonneville's Final 2002 Power Rates will expire at the end of fiscal year 2006. Expectations of rate levels in the period after fiscal year 2006 will affect whether such customers increase or decrease the amount of load they place on Bonneville.

In view of the foregoing and other circumstances, Bonneville faces some uncertainty with regard to the amount of power load Bonneville will be required to meet after fiscal year 2006, and hence the amount of power it may have to obtain in addition to existing Federal System generating resources. Bonneville is currently engaged in a discussion with customers and other interested parties in the Northwest Region (the "Regional Dialogue"). The Regional Dialogue seeks to address Bonneville's role in meeting Regional electric power load in the future. In the context of the Regional Dialogue, in July 2004, Bonneville published a document entitled, "Regional Dialogue—Bonneville Power Administration's Policy Proposal for Power Supply Role for Fiscal Years 2007-2011" (the "Draft Strategy"). Under the Draft Strategy, Bonneville has indicated to Regional customers its concerns that it not be placed in the position of attempting to acquire a substantial portion of the Region's power needs, as occurred in calendar year 2001 during the West Coast energy crisis. Bonneville stated that it would prefer to achieve these objectives by limiting the incremental load obligations Bonneville would bear above existing Federal System generating resources.

As a means of balancing its statutory obligation to meet electric power load 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 would prefer to have customers in the Region assume the role of meeting their own incremental power needs. Under the Draft Strategy, Bonneville would propose to meet only electric power load placed on it by Preference Customers and Federal agencies in roughly the same amount as is currently the case. Bonneville would not propose to meet either DSI or Regional IOU loads. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—Preference Customer and Federal Agency Loads." At present, Bonneville assumes that sales to Preference Customer and Federal agencies will equal slightly more than currently-contracted amounts and that Bonneville will continue to serve a similar amount of load during the 2007-2011 fiscal year period, with some increase to accommodate expected load growth of certain Preference Customers. Bonneville projects that such load will exceed firm Federal resources modestly, given the expected generating capability of the Federal System, with a projected deficit of about 15 average megawatts in fiscal year 2007 increasing to about 190 average megawatts by fiscal year 2011.

As a supplemental tool to help manage the risk of additional load being placed on Bonneville, the Draft Strategy provides that Bonneville would consider a proposal to limit the amount of firm power sales Bonneville makes at embedded cost rates to roughly the output of the existing Federal System. One means of implementing this approach would be to use a "tiered rate" design for Subscription power sales in the period after 2006. Under tiered rates, costs of new power purchases above the existing Federal System generating resources would not be melded with the comparatively low embedded costs of Federal System resources. Rather, the costs of the new power purchases would be separately recovered under an additional power rate or rate mechanism. To the extent a customer's purchases from Bonneville would be allocated for recovery under such a rate or rate mechanism, then the customer would bear the costs of the related incremental power purchases.

The Draft Strategy proposes that Bonneville not plan to sell power to DSIs in the period after fiscal year 2006; however, the Draft Strategy also proposes that Bonneville provide qualifying DSIs with financial payments roughly approximating the economic value of about 500 megawatts of Federal System power as determined by reference to then applicable power rates charged to Preference Customers and market prices. Under the Draft Strategy, any such benefits would be targeted to DSIs that operate, that are creditworthy and that have fully met their take or pay obligations under their Subscription contracts. Under the Draft Strategy, Bonneville would provide these benefits only if such actions actually enable aluminum production and maintain Pacific Northwest jobs. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Power Marketing in the Period After Fiscal Year 2001—DSI Loads."

Notwithstanding the direction of the Draft Strategy, the ultimate load obligations that Bonneville will assume will depend on a number of factors, including the outcome of the Regional Dialogue, and hence are uncertain. Bonneville does not anticipate finally resolving its load obligations in the post-fiscal year 2006 period until some time during fiscal year 2005. If Bonneville were to enter into physical power sales obligations to Regional IOUs to effect the Residential Exchange Settlement Agreements and/or to DSIs or others, without corresponding reductions in power sales to Regional Preference Customers, Bonneville could have larger generating resource deficits. This could increase the amount of power purchases that Bonneville would have to make, perhaps substantially.

POWER BUSINESS LINE

Description of the Generation Resources of the Federal System

Generation

Bonneville has statutory obligations to meet certain electric power loads placed on it by certain Regional customers. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region." To meet these loads Bonneville relies on an array of power resources and power purchases, which, together with the Bonneville-owned transmission system and certain other features, constitute the Federal System. The Federal System includes those portions of the federal investment in the Regional hydroelectric projects that have been allocated to power generation. Such projects were constructed and are operated by the Corps or the Bureau. The Federal System also includes power from non-federally-owned generating resources, including but not limited to the Columbia Generating Station and contract purchases from other power suppliers.

Federal Hydro Generation

Hydropower from federally-owned hydroelectric projects currently supplies approximately 73% of Bonneville's firm power supply. Bonneville also has acquired a small amount of power from non-federally-owned hydroelectric projects. Bonneville's large resource base of hydropower results in operating and planning characteristics that differ from those of major utilities that lack a substantial hydropower base. See the table entitled "Operating Federal System Projects for Operating Year 2006."

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

Bonneville defines "firm power" as electric power that (i) is continuously available from the Federal System even during the most adverse water conditions, and (ii) is useful for meeting Federal System firm loads. The amount of firm power that can be produced by the Federal System and marketed by Bonneville is based on "critical water" assumptions, *i.e.*, the worst low-water period on record for the Columbia River Basin. Firm power can be relied on to be available when needed. Firm power has two components: peaking capacity and firm energy. Peaking capacity refers to the generating capability to serve particular loads at the time such power is demanded. This is distinguishable from firm energy, which refers to an amount of electric energy that is reliably generated over a period of time. Bonneville has estimated that in Operating Year 2006, the Federal System, including firm energy purchases, would be capable of producing about 9580 average megawatts of firm energy under certain assumptions of low water conditions. In conducting loads and resources evaluations Bonneville utilizes the term "operating year," meaning the twelve calendar months beginning each August 1. See the following table "Operating Federal System Projects For Operating Year 2006."

The Federal System is primarily a hydropower system in which the peaking capacity exceeds Federal System peaking loads and power reserve requirements in most water years. Bonneville estimates that in most months its peaking capacity, for long-term planning purposes, will meet or exceed its requirements for the next ten years. Bonneville expects this excess of peaking capacity to persist, because most new resources added to meet firm energy needs will also contribute more peaking capacity. As a result, Bonneville's resource planning, to the extent Bonneville may need additional resources to meet its load obligations, focuses on the need to develop sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal-, gas-, oil- and nuclear-based generating systems must focus their resource planning on having enough peaking capacity to meet peak loads.

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

In general, for long-term resource planning purposes Bonneville estimates the amount of electric power it will acquire to meet loads above the firm power that the Federal System is expected to generate under certain low water conditions. For ratemaking and financial planning purposes however, Bonneville takes into account the amount of electric power it expects to have available to market based on average water conditions. The energy that Bonneville has to market above critical water assumptions in a specified period is referred to as seasonal surplus energy. The amount of seasonal surplus energy generated by the Federal System depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2006, assuming average water conditions (median water flows), the Federal System is estimated to generate an annual energy surplus of about 2310 average megawatts. In wet water conditions (high water flows) the amount of annual energy surplus could be as much as 3870 average megawatts. In low water years, the amount of seasonal surplus energy generated by the Federal System could be quite small.

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

The Corps and the Bureau operate the federally-owned hydroelectric projects in the Region to serve multiple statutory purposes. These purposes may include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection and power generation. Non-power purposes have placed requirements on operation of the reservoirs and have thereby limited hydropower production. Bonneville takes into account the non-power requirements and other factors in assessing the amount of power it has available to market from these projects.

These requirements change the shape, availability and timeliness of Federal hydropower to meet load. The information in the following table 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 dated December 2000 ("2000 Biological Opinion"), and a U.S. Fish and Wildlife Service ("Fish and Wildlife Service") biological opinion issued in 2000, for the Snake River and Columbia River projects. These measures include increased flow augmentation for juvenile fish migrations in the Snake and Columbia Rivers in the spring and summer, mandatory spill requirements at the Lower Snake and Columbia 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, such as the 2004 Biological Opinion (see "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line —Fish and Wildlife—Endangered Species Act—2000 and 2004 Biological Opinions") and similar constraints are introduced to the hydropower system, those changes will be reflected, as and when appropriate, in the availability of Federal hydropower under all water conditions.

Other Generating 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 has a two-year maintenance and refueling schedule and refueling is scheduled to occur in Operating Year 2005. Accordingly, for Operating Year 2006, the estimated output of the Columbia Generating Station assumes no scheduled downtime for refueling and maintenance. In addition, Bonneville has a number of power purchase contracts that are not tied to specific generating resources. The amount of power purchased under these contracts increased substantially from prior years as Bonneville used such contracts to obtain electric power needed to meet the increased loads taken on by Bonneville under the Subscription Strategy.

Operating Federal System Projects For Operating Year 2006

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, streamflow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes a fifty-year record of river flows based on the period from 1929-1978 for planning purposes. During this historical period, low water conditions ("Low 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 2006, 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 2006[(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	6,234	3,147	2,462	1,952
Hungry Horse	1952	4	361	126	102	77
Other Bureau Projects[(6)]		16	225	164	156	130
1. Total USBR Projects		53	6,820	3,437	2,720	2,159
United States Army Corps of Engineers Hydro Projects						
Chief Joseph	1955	27	2,535	1,668	1,340	1,066
John Day	1968	16	2,484	1,474	1,101	800
The Dalles including Fishway[(7)]	1957	24	2,078	1,073	826	600
Bonneville including Fishway	1938	20	1,059	597	542	364
McNary	1953	14	1,127	738	693	521
Lower Granite	1975	6	930	453	340	218
Lower Monumental	1969	6	923	443	311	220
Little Goose	1970	6	928	440	320	215
Ice Harbor	1961	6	693	379	266	137
Libby	1975	5	566	302	221	168
Dworshak	1974	3	444	234	189	126
Other Corps Projects[(8)]		20	398	294	269	225
2. Total USACE Projects		153	14,163	8,097	6,422	4,660
3. Total USBR and USACE Projects (line 1 + line 2)		**206**	**20,985**	**11,534**	**9,142**	**6,819**
Non-Federally-Owned Projects						
Columbia Generating Station[(9)]	1984	1	1,150	1,000	1,000	1,000
Other Non-Federal Hydro Projects[(10)]		5	32	59	47	45
Other Non-Federal Projects[(11)]		12	65	121	121	121
4. Total Non-Federally-Owned Projects		**18**	**1,247**	**1,180**	**1,168**	**1,166**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases[(12)]		**n/a**	**1,369**	**1,596**	**1,596**	**1,596**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**224**	**23,601**	**14,310**	**11,906**	**9,581**

Source: 2003 Pacific Northwest Loads and Resources Study, Bonneville, December 2003.

(1) Operating Year 2006 is August 1, 2005 through July 31, 2006.

(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.

(3) Maximum energy capability is the estimated amount of hydro energy to be produced using High Water Flows in average megawatts of energy. The hydro-regulation study incorporates measures from the 2000 Biological Opinion, defined hereafter, and the Fish and Wildlife Service's 2000 Biological Opinion. The effects of the 2004 Biological Opinion will be incorporated into future hydro-regulation studies, if and to the extent the effects of such biological opinion are different than assumed under the 2000 Biological Opinion. 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, in average megawatts of energy.

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

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

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

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

(9) Columbia Generating Station has a two-year maintenance and refueling schedule. For Operating Year 2005, the estimated output of the Columbia Generating Station was reduced to reflect scheduled maintenance and refueling. For Operating Year 2006 the Columbia Generating Station estimated output assumes no outage for maintenance and refueling.

(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) (formally 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 (1927) and Elwah (1910) hydro projects, shares of Foote Creek, LLC's Foote Creek 1 (1999), Foote Creek 2 (1999), Foote Creek 4 (2000) wind projects, a share of PacifiCorp Power Marketing and Florida Light and Power's Stateline wind project, Condon Wind Project LLC's Condon wind project, NWW Wind Power's Klondike Phase 1 wind project, and a share of the City of Ashland's solar project. Calpine's Fourmile Hill Geothermal project has been postponed to October 1, 2007.

(12) Bonneville Contract Purchases include: Subscription Strategy Augmentation Purchases and other contracts by Bonneville 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 revenues derived from these customers provide Bonneville with a large portion of the funds needed to pay its costs. For information regarding the relative amounts of customer revenue and other information, see the table entitled "Federal System Statement of Revenues and Expenses" under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data." Bonneville also earns revenues from the provision of transmission service to the foregoing and other customers. See "TRANSMISSION BUSINESS LINE—Bonneville's Transmission System."

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

Preference Customers

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

Direct Service Industrial Customers

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

Regional Investor-Owned Utilities

As part of Bonneville's Subscription Strategy, Bonneville entered into certain agreements, as amended, with all six of the Regional IOUs in settlement of Bonneville's statutory obligation to provide benefits under the Residential Exchange Program for specified periods beginning October 1, 2001. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program," "—Power Marketing in the Period After Fiscal Year 2001," "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data," "—Power Marketing in the Period After Fiscal Year 2001—Subscription Power Rates" and "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

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

Exports of Surplus Power to the Pacific Southwest

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

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

In 1995, in view of the Regional load diversification away from Bonneville that was then occurring, Congress enacted a law that 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 expect to have substantial new amounts of such excess federal power to sell during the remainder of the five-year rate period ending September 30, 2006.

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

While Bonneville designs its power rates, including its rates for out-of-Region power sales, to recover its costs, it does so 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 1991-2001

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

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

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

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

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

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

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

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

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

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

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

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

Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region

The Northwest Power Act requires Bonneville to meet certain firm loads in the Region placed on Bonneville by contract by various Preference Customers and Regional IOUs. Bonneville does not have a statutory obligation to meet all firm loads within the Region or to enter into contracts to sell any power directly to a DSI after fiscal year 2001.

Under the Northwest Power Act, when requested, Bonneville must offer to sell to each eligible utility, which includes Preference Customers and Regional IOUs, sufficient power to meet that portion of the utility's Regional firm power loads that it requests Bonneville to meet. The extent of Bonneville's obligation to meet the firm loads of a requesting utility is determined by the amount by which the utility's firm power loads exceed (1) the capability of the utility's firm peaking capacity and energy resources used in operating year 1979 to serve its own loads; and (2) such other resources as the utility determines, pursuant to its power sales contract with Bonneville, will be used to serve the utility's firm loads in the Region. If Bonneville has or expects to have inadequate power to meet all of its contractual obligations to its customers, certain statutory and contractual provisions allow for the allocation of available power. 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 Marketing After Fiscal Year 2006."

As required by law, Bonneville's power sales contracts with Regional utilities contain provisions that require prior notice by the utility before it may use, or discontinue using, a generating resource to serve such utility's own firm loads in the Region. The amount of notice required depends on whether Bonneville has a firm power surplus and whether the Regional utility's generating resource is being added to serve or withdrawn from serving the utility's own firm load. These provisions are designed to give Bonneville advance notice of the need to obtain additional resources or take other steps to meet such load.

Some of Bonneville's Preference Customers and all of its Regional IOU customers have generating resources, which they may use to meet their firm loads in the Region. Under requirements power sales contracts that expired in fiscal year 2001, each of these customers had to identify annually the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are also included in all Subscription Agreements under which Bonneville has a load following obligation. In connection with its Subscription Strategy, Bonneville tendered proposed requirements power sales contracts to each of the Regional IOUs for specified periods following the expiration of the IOUs' requirements contracts at the end of fiscal year 2001. All of the Regional IOUs elected not to execute such agreements.

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 in the Subscription contract and power rate development process; (ii) the amount of Augmentation Purchases that Bonneville will have to make to meet Subscription loads; (iii) future non-power operating requirements from future biological opinions or amendments to biological opinions; (iv) the availability of new generation resources or contract purchases available in the Pacific Northwest to meet future Regional loads; (v) changes in the regulation of power markets at the wholesale and retail level; and (vi) the overall load growth from population changes and economic activity within the Region. 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 Pacific 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. Given uncertainties over the amount of loads that Bonneville will be required to meet in the long term, any resource investment that involves irrevocable, high fixed costs over a period longer than Bonneville's contracted load obligation is much riskier than it would have been in the past. Bonneville has indicated to Regional interests that Bonneville would prefer in the future to avoid assuming the responsibility of meeting incremental Regional power loads above the generating capability of the existing generating resources of the Federal System. Bonneville has also indicated that it would consider using tiered power rates under which the anticipated higher cost of electric power from new power purchases to meet such incremental loads would be recovered from customers to the extent they place incremental load obligations on Bonneville. See "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Power Marketing After Fiscal Year 2006."

Should Bonneville assume incremental load obligations above the existing generating resources of the Federal System, Bonneville believes that, in general, new resources should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available and should have costs that can be offset when hydroelectric power is available. Therefore, Bonneville's current resource strategy, in general, is to acquire resources that can accommodate yearly fluctuations in Bonneville loads and that add flexibility to the system.

Short-term (less than five year) purchases are the only type of resource that meets this resource acquisition strategy. Short-term purchases almost always will fit these conditions better than other resources, including long-term combustion turbine resources, because purchases generally do not involve incurring high, long-term fixed costs.

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

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

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

Bonneville's short-term resource purchase strategy is complemented by two other opportunities. First, Bonneville seeks to acquire power from renewable resources. The bulk of such purchases is likely to be from wind generation because of the increasing cost-effectiveness of wind generation projects and the expectation that the new wind generation projects can become operational within 12-18 months of a decision to proceed. The amount of wind energy resources that

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

As a second short-term resource strategy, Bonneville encourages electric power conservation measures. Bonneville provides a $.50 per megawatt-hour rate discount to those of its customers that implement conservation measures and/or renewable resource projects. In addition, Bonneville is purchasing about 100 average megawatts of electric power conservation through fiscal year 2006 as part of its conservation-augmentation strategy. Any such resource development should lessen Bonneville's reliance on spot market power purchases.

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

Under the Subscription Strategy, Bonneville substantially increased its contracted load obligation, which led Bonneville to make Augmentation Purchases. Consistent with the foregoing resource strategy, Bonneville has relied primarily on short-term (five years or less) purchase agreements to meld with firm power and seasonal surplus energy from the Federal System to meet these additional firm loads. See "—Power Marketing in the Period After Fiscal Year 2001."

Residential Exchange Program

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

Under the Residential Exchange Program, Bonneville 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 PF rate, if such PF rate is lower. See "MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES—Bonneville Ratemaking and Rates." The net costs of the Residential Exchange Program are shown in the Federal System Statement of Revenues and Expenses set forth under "BONNEVILLE FINANCIAL OPERATIONS—Historical Federal System Financial Data."

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

Fish and Wildlife

General. The Northwest Power Act directs Bonneville to protect, mitigate and enhance fish and wildlife resources to the extent they are affected by federal hydroelectric projects on the Columbia River and its tributaries. Bonneville makes expenditures and incurs other costs for fish and wildlife consistent with the Northwest Power Act and the Council's Columbia River Basin Fish and Wildlife Program (the "Council Program"). In addition, in the wake of certain listings of fish species under the ESA as threatened or endangered, Bonneville is financially responsible for expenditures and other costs arising from conformance with the ESA and certain biological opinions prepared by the 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 the Bureau that is allocated by law or pursuant to policies promulgated by FERC's predecessor to the federal projects' power purpose (as opposed to other project purposes such as irrigation, navigation and flood control). These measures mitigate for the impact on fish and wildlife of the construction and operation of hydroelectric dams of the Federal System.

Bonneville also implements and funds measures proposed in the Council Program, which the Council periodically amends. The Council Program calls for a variety of mitigation measures from habitat protection to mainstem Columbia River and Snake River flow targets. When such measures affect the operation of the Federal System and force Bonneville to purchase power to fulfill contractual demands or to spill water and thereby forgo generation of electricity, for instance, those financial losses are counted as measures funded by Bonneville. While many of the measures in the Council's Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's Program measures, especially those designed to benefit species not listed under the ESA, are in addition to ESA-directed measures. See "—Council's Fish and Wildlife Program."

Bonneville's fish and wildlife costs fall into two main categories, "Direct Costs" and "Operational Impacts," both of which are driven primarily by ESA requirements. Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing the Council Program, and which include expense and capital components for ESA–related and some non-ESA-related measures that are located at sites away from the Federal System dams; (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps, Bureau and Bonneville; and, (iii) "Other Entities' O&M," which include fish and wildlife O&M costs of the Fish and Wildlife Service for the Lower Snake River Hatcheries and of the Corps and Bureau for Federal System projects.

"Operational Impacts" include "Replacement Power Purchase Costs" and "Foregone Power Revenues." Replacement Power Purchase Costs are the costs of certain power purchases made by Bonneville that are attributable to river operations in aid of fish and wildlife. To determine these costs in a given year, Bonneville compares the actual hydroelectric generation in such year against the hydroelectric generation that would have been produced had the hydroelectric system been operated without any fish and wildlife operating constraints. To the extent that this comparison indicates that Bonneville made a power purchase to meet load, which purchase Bonneville would not have had to make had the river been operated free of fish constraints, Bonneville accounts for such value as a fish and wildlife cost. "Foregone Power Revenues," are revenues that would have been earned absent changes in hydroelectric system operations attributable to fish and wildlife.

Bonneville estimates that in aggregate, Direct Costs and Replacement Power Purchase Costs were about $479.3 million in fiscal year 2004. In addition, Bonneville estimates that it had about $21.7 million in Foregone Power Revenues.

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

Among other things, the ESA requires that federal agencies such as Bonneville, the Corps and the Bureau, take no action that would jeopardize the continued existence of listed species or result in the destruction or adverse modification of their critical habitat. Since 1991, there have been listed as threatened or endangered under the ESA 12 species of anadromous fish (salmon and steelhead) that are affected by operation of the Federal System. It is possible that other species may be listed or proposed for listing in the future. In general, the effect of the listing of the fish species under the ESA, and certain other operating requirements resulting from Bonneville's fish and wildlife obligations under the Northwest Power Act, is that, except in emergencies, the Federal System is now operated for power production after meeting needs for flood control and the protection of ESA-listed fish.

In connection with the listing of these species, NOAA Fisheries has prepared certain biological opinions addressing the listed species. The biological opinions provide information that Bonneville, the Corps and the Bureau can use to ensure that their actions with respect to the operation of the Federal System satisfy the ESA. By acting consistently with the biological opinions, Bonneville, the Corps and the Bureau generally demonstrate that jeopardy to listed species is being avoided. Specifically, Bonneville, the Corps and the Bureau have chosen to implement certain specified measures recommended in the biological opinions as being necessary to avoid jeopardy. The adequacy of the biological opinions and their implementation are subject to, and have been subjected to, judicial review.

Operation of the Federal System consistent with the biological opinions has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise be run through turbines to generate electricity may be spilled to aid in downstream fish migration without producing electric energy. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration.

Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these changes, under certain water conditions, Bonneville has had to, and may have to, purchase additional energy for the fall and winter to meet load commitments than would otherwise have been met with the hydroelectric system. In addition, the flow changes have meant that Bonneville has had comparatively more surplus energy to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System in conformance with the biological opinions and the Council Program, as in effect as of the beginning of fiscal year 2000, decreased Federal System generation capability by about 1000 average megawatts, assuming average water conditions, from levels immediately preceding the issuance of the first biological opinion in 1995. The consequences of this decrement in generation are reflected in the Replacement Power Purchase Costs and Foregone Power Revenues described above.

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

These ESA listings and related actions to protect listed species and their habitat have also resulted in substantial cost increases to Bonneville. Prior to the initial ESA listings, Bonneville fish costs increased from about $20 million in fiscal year 1981 to $150 million in fiscal year 1991. After the issuance of the first biological opinion affecting Federal System operations, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in 1995. As noted above, Bonneville estimates that the total of Direct Costs and Operational Impacts in fiscal year 2003 was about $518.8 million and about $501 million in fiscal year 2004.

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 and they are intended to be mutually consistent. 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 that would have called for breaching four Federal System Snake River dams. The direct cost of breaching the dams would be very high. In addition, the loss of the generation from the dams would substantially affect the power generation capability of the Federal System, reducing current expected output by approximately 1200 average megawatts under average water assumptions, resulting in significantly increased power purchases and/or lost power sales.

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 is inadequate because it relied on offsite mitigation measures that were "not reasonably certain to occur." In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court. On November 30, 2004, NOAA Fisheries finalized the 2004 Biological Opinion to replace the 2000 Biological Opinion and address the deficiencies therein identified by the reviewing court.

The 2004 Biological Opinion calls 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 calls 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 the Bureau, estimate 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 does 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. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

The adoption by NOAA Fisheries of the 2004 Biological Opinion has prompted additional litigation based on alleged violations of the ESA. Bonneville is unable to predict the manner in which or likelihood that such litigation will affect the 2004 Biological Opinion. See "BONNEVILLE LITIGATION—ESA Litigation—National Wildlife Federation v. National Marine Fisheries Service."

<u>Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville</u>. In 1995, the United States Treasury, the Office of Management and Budget, DOE and other agencies agreed to provide for certain federal repayment credits to offset some of Bonneville's fish and wildlife costs. The foregoing agencies agreed that Bonneville would implement a previously unused provision of the Northwest Power Act, section 4(h)(10)(C). This provision allows Bonneville to exercise its Northwest Power Act authorities to implement fish and wildlife mitigation on behalf of all of a project's Congressionally authorized purposes, such as irrigation, navigation, power and flood control, then recoup (*i.e.*, take a credit for) the portion allocated to non-power purposes. The agreement also directs Bonneville to recoup certain Direct Costs and Replacement Power Purchase Costs. The amount of such recoupments was about $354 million, $38 million, $97 million, and $77 million in fiscal years 2001, 2002, 2003, and 2004, respectively. These credits are treated as revenues in Bonneville's ratemaking process, and such recoupments are taken against Bonneville's lowest priority financial obligation, its payments to the United States Treasury. The recoupments are initially taken based on estimates and are subsequently modified to reflect actual data. Two important costs that may be recouped under section 4(h)(10)(C) are the cost of foregone power revenues and replacement power purchases arising from certain hydroelectric system operations for the benefit of fish and wildlife. Both of these categories of costs can occur to a greater degree in dry years when, historically, market prices for power are comparatively high. Thus, Bonneville believes that the amount of 4(h)(10)(C) recoupments will tend to be greater in dry years when power prices tend to be high and Bonneville has less power to market, and therefore tends to have lower power revenues.

<u>Council's Fish and Wildlife Program</u>. In November 2002, the Council adopted a new Fish and Wildlife Program (the "2002 Program"). The 2002 Program focuses on an ecosystem approach to rebuilding fish and wildlife populations in the Columbia River Basin, consistent with the 2000 Biological Opinion. Estimated costs to Bonneville of the Council's measures, as then encompassed in amendments to the Council's 1995 Program, were included in Bonneville's assumptions for the 2002 Final Power Rates. The 2002 Program, like the Council's predecessor program, sets forth an "integrated program" budget to Bonneville for both the Council Fish and Wildlife Program and the off-site mitigation program under the 2000 Biological Opinion. The costs of the integrated program ("Integrated Program Costs") are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—Fish and Wildlife—General." The 2002 Program has not yet been updated to reflect the 2004 Biological Opinion.

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

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

Power Marketing in the Period After Fiscal Year 2001

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

Preference Customer 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. With the exception of eight contracts having terms of five years and representing about 800 average megawatts of load, such agreements have terms of ten years. 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 average megawatts annually.

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

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

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

The Slice of the System (or "Slice") contracts require that customers make monthly payments based on forecasted costs of the Federal System, with specific exceptions. These monthly payments are subject to an annual "true up" adjustment for actual costs. The Slice customers have the right to have an outside auditing firm conduct an audit of such annual "true up" adjustments and costs. Certain Slice customers requested such an audit of the fiscal year 2002 "true up" adjustment and costs, and retained an accounting firm to conduct an audit and prepare a final report, which was completed on June 13, 2003. The Slice customer audit asserted that the Slice customers' payments for fiscal year 2002 should be adjusted by removing $83 million from Bonneville's charges. Bonneville issued a 'Response to the Final Slice Audit Report' ("Response") and rejected some of the adjustments. Some of Bonneville's non-Slice customers have filed litigation with the Ninth Circuit Court challenging Bonneville's Response. Currently, Bonneville, the non-Slice customer litigants and the Slice customers are in settlement mediation on the matter. Bonneville made about $31 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 result of the mediation, or alternatively the litigation, pertaining to the true-up payments for fiscal year 2002, it is possible that the true-up payments with respect to fiscal years 2003 and 2004 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 during such periods. For the five years beginning October 1, 2001, Bonneville originally contracted to satisfy this obligation through (i) direct sales of 1000 average megawatts of firm power at Bonneville's Residential Load Rate ("RL Rate") and a similar rate in the case of a comparatively small Regional IOU, and (ii) cash payments for an exchange value ("Monetary Benefits" as described immediately below) of 900 average megawatts of firm power. The RL Rate is set at a level equivalent to Bonneville's lowest available requirements service rate, the PF Rate. The "Monetary Benefits" are based on the related amount of power multiplied by the difference between a forecast of the market price of power set in Bonneville's rate case and the RL Rate. All power sales and payments by Bonneville under the Residential Exchange Settlement Agreements, as amended, are provided for the benefit of the Regional IOUs' residential and small farm loads in the Region.

Subsequent to the execution of the original Residential Exchange Settlement Agreements, Bonneville and the Regional IOUs entered into a number of contract amendments and supplemental arrangements relating to the five-year rate period beginning October 1, 2001. These amendments and arrangements increased the amount of cash payments that Bonneville would make in respect of the Residential Exchange Settlement Agreements and reduced the amount of physical power sales thereunder. As result, the aggregate cash payments to Regional IOUs that Bonneville has made related to the Residential Exchange Settlement Agreements were about $355 million in fiscal year 2002, $327 million in fiscal year 2003 and $388 million in fiscal year 2004. Under a variety of assumptions, such payments are projected to be about $382 million in fiscal year 2005, and $365 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 LB-CRAC, FB-CRAC and SN-CRAC rate level adjustments. The above 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 of roughly $25 million per year.

The aggregate cash payments to Regional IOUs described above can be broken down into three main components. The first component reflects payments for Monetary Benefits under the original Residential Exchange Settlement Agreements. Monetary Benefits paid by Bonneville were approximately $143 million in each of fiscal years 2002 and 2003 and $128 million in fiscal year 2004. Projected Monetary Benefits to be paid by Bonneville are $143 million and $137 million in fiscal years 2005 and 2006, respectively.

The second component is the reflection of certain agreements by Regional IOUS to defer payments from Bonneville relating to the Residential Exchange. These deferrals reshaped the payments by Bonneville within the current five-year rate period. The deferrals resulted in a reduction in payments to the Regional IOUs in fiscal years 2002 and 2003 and comparably increased payments in 2004. Payment by Bonneville of the deferred amount was about $33 million in fiscal year 2004.

The third component 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 a settlement of certain litigation filed by Preference Customers challenging Bonneville's authority to enter into the Residential Exchange Settlement Agreements. In June 2004, Bonneville and two Regional IOUs (Puget and PacifiCorp) entered into agreements that 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 to the foregoing reduction in payments, Bonneville and such Regional IOUs agreed that Bonneville could defer paying until fiscal years 2007-2011 the remaining $100 million aggregate amount (plus interest) otherwise owed by Bonneville to the two Regional IOUs in fiscal years 2005 and 2006. In return, the two Regional IOUs obtained assurances from Bonneville as to the amount and nature of Residential Exchange Settlement benefits to be provided to them by Bonneville in fiscal years 2007-2011, as described below.

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. Taking into account the initial load reduction payment obligations, the contract conversions to monetary payments and the effects of the foregoing litigation discounts, Bonneville made payments to Regional IOUs in respect of the load reductions and conversions in the amount of $227 million in aggregate in fiscal year 2004 and expects to make similar payments thereto in the aggregate amount of $244 million in fiscal year 2005 and $236 million in fiscal year 2006.

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

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

As a result of certain 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 deferred amount of $100 million plus interest to Puget and PacifiCorp referred to above. In addition, Bonneville and the Regional IOUs have agreed to an independent market price indicator for determining Monetary Benefits in such period, rather than the use of market price indicators developed by Bonneville in its power rate cases.

The Residential Exchange Settlement Agreements and the subsequent agreements between Bonneville and the related Regional IOUs relating thereto have been challenged in court by other Bonneville customers. See "BONNEVILLE LITIGATION—Residential Exchange Program Litigation."

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

The 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 these original Subscription contracts, Bonneville's contracted sales obligations to aluminum company DSIs in fiscal year 2005 and 2006 are about 200-300 average megawatts. The remainder of the sales to aluminum company DSIs (i) have been curtailed by contract amendment, (ii) were terminated because they were rejected in bankruptcy proceedings, or (iii) are not being performed by related DSIs pending likely rejection in bankruptcy proceedings. Currently, four aluminum company DSIs are under bankruptcy protection. See "BONNEVILLE LITIGATION—GNA Bankruptcy," "—Kaiser Aluminum Bankruptcy," and "—Longview Aluminum Bankruptcy." In view of the foregoing bankruptcies and continued low prices for aluminum relative to the costs of production, and in particular the current and expected price of electric power in the Western United States, Bonneville's expectation is that aluminum company DSI loads will remain at very low levels through at least fiscal year 2006.

Subscription Strategy Contracts Opt-Out Provisions. While Bonneville and its customers have entered into the foregoing Subscription contracts, the ultimate amount of electric power load Bonneville is and will become obligated to meet under such contracts through fiscal year 2011 remains somewhat uncertain because, among other reasons, the Subscription contracts have provisions allowing customers to terminate such contracts if either FERC or the Ninth Circuit Court, which reviews FERC actions on Bonneville's rates, subsequently remands Bonneville's base power rates and Bonneville publishes a record of decision that adopts different rates for such period. The customers may not opt out of their contracts solely on the basis that Bonneville has included the cost recovery adjustment clauses in the rate proposal or that the cost recovery adjustment clauses are employed to increase rate levels. The customers who do not opt out after review of the final rate proposal would be committed to purchase as provided in their Subscription contracts. The 2002 Final Power Rates were approved by FERC in July 2003 but are the subject of litigation in the Ninth Circuit Court. See "BONNEVILLE LITIGATION—2002 Final Power Rates Challenge."

Subscription Power Rates. On June 29, 2001, Bonneville filed its proposed 2002 Final Power Rate Proposal with FERC for the five years beginning October 1, 2001. On July 21, 2003, FERC granted final approval of such rates, although they 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 intra-rate period adjustments that increase or decrease power rate levels depending on certain conditions. The base rate levels are between approximately 1.9 cents per kilowatt-hour and 2.3 cents per kilowatt-hour, excluding transmission and depending on type of service. The base rates are at levels similar to those in effect for like service in the immediately preceding rate period. The 2002 Final Power Rates also include three intra-rate period adjustment mechanisms under which Bonneville can increase, and in some instances decrease, power rate levels: a Load Based Cost Recovery Adjustment Clause ("LB-CRAC"), a Financial Based Cost Recovery Adjustment Clause ("FB-CRAC") and a Safety Net Cost Recovery Adjustment Clause ("SN-CRAC").

The LB-CRAC is designed to recover the net cost of system Augmentation Purchases and certain load reduction agreements that is over and above the cost of such purchases that Bonneville forecasted in a rate filing prepared in July 2000. The LB-CRAC is not designed to recover the cost of replacing reductions in the firm power generating capability included in the baseline estimate of Federal System firm power if any such reductions occur.

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

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

The SN-CRAC is to be implemented to recover costs on a temporary basis if, at any time during the rate period, Bonneville were to (i) forecast a 50% probability or greater of missing a scheduled payment to the United States Treasury or other creditor or (ii) miss a scheduled payment to the United States Treasury or other creditor. A rate level increase under the SN-CRAC occurs independently of any LB-CRAC or FB-CRAC increase then in effect.

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

With respect to the SN-CRAC, in June 2003, Bonneville issued a final proposal and record of decision for an SN-CRAC rate level adjustment (the "2004 SN-CRAC Rate Level Adjustment"). On May 10, 2004, FERC approved the 2004 SN-CRAC Rate Level Adjustment.

The 2004 SN-CRAC Rate Level Adjustment is a variable contingent mechanism where the calculation of the actual rate level adjustment for a fiscal year is made shortly before the beginning of such fiscal year. The adjustment is based on then current forecasts of the Power Business Line accumulated net revenues for the fiscal year preceding the fiscal year in which the rate level adjustment is to be in effect. Thus, the first year (fiscal year 2004) rate level adjustment under the 2004 SN-CRAC Rate Level Adjustment was determined in August 2003 on the basis of then available financial forecasts of fiscal year end 2003 accumulated net revenues. Under that determination, Bonneville's SN-CRAC rate level adjustment applicable in fiscal year 2004 was about 10 percent. With respect to fiscal year 2005, in September 2004 Bonneville concluded that it would reduce to zero the rate level adjustment under the 2004 SN-CRAC Rate Level Adjustment.

Assuming the effects and the expected effects of the 2004 SN-CRAC Rate Level Adjustment and expected and actual rate level adjustments under the FB-CRAC and LB-CRAC, Bonneville's average power rates for fiscal years 2004-2006 are expected to exceed by more than 50 percent the rate levels in effect for like service in fiscal year 2001, the year preceding the current power rate period. As described in this Appendix A, the rate level increases under the rate adjustment mechanisms vary depending on the type of Subscription power sales contract. Some contracts are not subject to any of the rate adjustment mechanisms and some are subject only to some of such mechanisms. For a description of actual and projected Subscription power rate levels see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION--Subscription Strategy, Power Rates for Fiscal Years 2002-2006 and Recent Power Rate Developments" and the table "Bonneville Full Requirements Power Rate Levels 1996-2006."

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

Recovery of Stranded Power Function Costs

As a consequence of regulatory and economic changes in electric power markets, many utilities see potential for certain of their costs, in particular power system costs, to become unrecoverable, *i.e.,* "stranded." Stranded costs may arise where power customers are able, pursuant to new open transmission access rules, to reach new sources of supply, leaving behind unamortized power system costs incurred on their behalf. Bonneville could also face this concern. While Bonneville has separate statutory authority requiring it to assure that its revenues are sufficient to recover all of its costs, additional authority may be required to assure that 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 function may not be able to recover all of its costs in the event that Bonneville's cost of power exceeds market prices. See "—Power Marketing Plan for the Period After Fiscal Year 2001." Nonetheless, Bonneville cannot predict with certainty its cost of power or market prices.

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

Bonneville's rates for any FERC-ordered transmission service pursuant to sections 211/212 of the Federal Power Act are governed only by Bonneville's applicable law, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. In the opinion of Bonneville's General Counsel, provisions of the Northwest Power Act directing Bonneville to recover its total cost would be applicable to any stranded cost to be recovered by Bonneville were Bonneville ordered by FERC to provide transmission under 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. For a discussion of the proposed formation of a regional transmission organization that could affect some of Bonneville's transmission operation functions, see "TRANSMISSION BUSINESS LINE—Bonneville's Participation in a Regional Transmission Organization."

Changes in the Regulation of Regional Retail Power Markets

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

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

TRANSMISSION BUSINESS LINE

Bonneville provides a number of different types of transmission services to Regional Preference Customers, Regional IOUs, DSIs, other privately- and publicly-owned utilities, power marketers, power generators and others. Bonneville's revenues from the sale of transmission and related services accounted for roughly 17 percent of Bonneville's overall revenues in fiscal year 2004.

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

While it is difficult to generalize as to the cost of transmission service needed to effect various power transactions, a useful point of reference may be the cost borne by certain Regional full requirements Preference Customers of Bonneville's. These customers pay roughly $3.50 to $4.00 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 $2.50 to $3.00 per megawatt hour for transmission and ancillary services.

Bonneville's Transmission System

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

The Federal 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.

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 "—Proposals for Federal Legislation and Administrative Action Relating to Bonneville," and "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Fiscal Year 2005 Developments—President's Fiscal Year 2006 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"). These transmission project proposals are on hold but are expected to move forward when funding approaches can be finalized. With regard to the financing of the foregoing generation integration projects, Bonneville's current policy is to require that those applicants requesting that Bonneville provide transmission for new generating facilities bear the risk of stranded transmission interconnection costs by prepaying the related transmission investments and obtaining credits to their transmission bills from Bonneville.

Bonneville's current transmission system investment plan calls for Bonneville to make investments of about $300 million a year over the four fiscal years commencing October 1, 2004. To finance the foregoing investments, Bonneville expects to use a mix of United States Treasury borrowing and advance payments from transmission customer 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 Federal Power Act to authorize FERC to order a "transmitting utility" to provide access to its transmission system at rates, and upon terms and conditions, that are just and reasonable, and not unduly discriminatory with respect to the transmitting utility's own use of its transmission system.

While Bonneville is not generally subject to the Federal Power Act, Bonneville is a "transmitting utility" under the EPA-1992 amendments to sections 211/212 of the Federal Power Act. Therefore FERC may order Bonneville to provide others with transmission access over the Federal System transmission facilities. FERC's authority also includes the ability to set the terms and conditions for such FERC-ordered transmission service. However, the transmission rates for FERC-ordered transmission under EPA-1992 are governed only by Bonneville's other applicable laws, except that no such rate shall be unjust, unreasonable or unduly discriminatory or preferential, as determined by FERC. Based on the legislative history relating to the provisions of EPA-1992 applicable to Bonneville, Bonneville's General Counsel is of the opinion that Bonneville's rates for FERC-ordered transmission services under sections 211/212 are to be established by Bonneville, rather than by FERC, and reviewed by FERC through the same process and using the same statutory requirements of the Northwest Power Act as are otherwise applicable to Bonneville's transmission rates.

In April 1996, FERC issued an order, "Order 888," to promote competition in wholesale power markets. Among other things, Order 888 established a *pro forma* tariff providing the terms and conditions for non-discriminatory open access transmission service, and required all jurisdictional utilities to adopt the tariff. Order 888 also included a "reciprocity" provision that allows non-jurisdictional utilities to obtain non-discriminatory open access from transmitting utilities if the non-jurisdictional utility submits to FERC for its approval (i) an open access transmission tariff that substantially conforms to the *pro forma* tariff and (ii) transmission rates that are comparable to the rates the non-jurisdictional utility applies to itself.

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

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

Bonneville's Transmission and Ancillary Service Rates

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

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

Bonneville's transmission and ancillary services rates for fiscal years 2004-2005 were approved by FERC under the standards of the Northwest Power Act and under the reciprocity standards of Order 888. In addition to approving Bonneville's transmission rates under the Northwest Power Act, FERC stated that the rates and tariffs fulfill standards for open, nondiscriminatory transmission access. The 2004 transmission rates were not challenged in litigation. In Fall 2004, Bonneville commenced proceedings for transmission rates and tariffs for the next transmission rate period beginning October 1, 2005. In January 2005, Bonneville and its transmission customers signed a 2006 transmission rate case settlement agreement. Under the agreement, Bonneville would raise transmission rates on average by about 12.5 percent. While Transmission Business Line costs have increased somewhat, transmission sales are expected to be lower than in the recent past because 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. Bonneville's transmission rates vary depending on type of service purchased.

Bonneville's Participation in a Regional Transmission Organization

Following the issuance in May 1999 of a notice of proposed rulemaking on regional transmission organizations ("RTOs"), in January 2000 FERC issued a final rule on RTOs that establishes minimum characteristics and functions for an RTO and requires that each jurisdictional utility make certain filings regarding the formation of and participation in an RTO.

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 and determining that additional Regional support was necessary, the transmission owners, including Bonneville, in Spring 2003 resumed their engagement with Regional stakeholders through a "Regional Representatives Group" process 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 that proposed for RTO West and that would be subject to increased member control. Bonneville continues to participate in discussions with the Regional Representatives Group to further define this proposal.

In December 2004, Bonneville and eight other entities owning transmission facilities in the northwestern United States and in British Columbia unanimously voted to adopt bylaws for a new organization named Grid West. Various decisions are scheduled to be made about whether to continue this effort, including a decision scheduled for September 2005 on whether to establish an independent, developmental board of directors that would further develop the proposal. Assuming the effort moves forward, Bonneville would not make a decision about including Bonneville's transmission facilities in the Grid West program until late 2007 or early 2008. In April 2005, Bonneville filed a request for declaratory judgment with FERC seeking clarification on a number of regulatory and jurisdictional issues should development of Grid West proceed.

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.

MATTERS RELATING TO THE POWER AND TRANSMISSION BUSINESS LINES

Bonneville Ratemaking and Rates

Bonneville Ratemaking Standards.

Bonneville is required to periodically review and, as needed, to revise rates for power sold and transmission services provided in order to produce revenues that recover Bonneville's costs, including its payments to the United States Treasury. The Northwest Power Act incorporates the provisions of other Bonneville organic statutes, including the Transmission System Act and the Flood Control Act. The Transmission System Act requires, among other things, that Bonneville establish its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment to the United States Treasury. Substantially the same requirements are set forth in the Flood Control Act.

Bonneville Ratemaking Procedures

The Northwest Power Act contains specific ratemaking procedures used to develop a full and complete record supporting a proposal for revised rates. The procedures include publication of the proposed rate(s), together with a statement of justification and reasons in support of such rate(s), in the Federal Register and a hearing before a hearing officer. The hearing provides an opportunity to refute or rebut material submitted by Bonneville or other parties and also provides a reasonable opportunity for cross-examination, as permitted by the hearing officer. Upon the conclusion of the hearing, the hearing officer certifies a formal hearing record (including hearing transcripts, exhibits and such other materials and information as have been submitted during the hearing) to the Bonneville Administrator. This record provides the basis for the Administrator's final decision, which must include a full and complete reasoning in support of the proposed rate(s).

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

Rates established by Bonneville under the Northwest Power Act may become effective only upon confirmation and approval by FERC, although FERC may grant interim approval of Bonneville's proposed rates pending FERC's final confirmation and approval.

FERC's review of Bonneville's firm power rates, Regional non-firm energy rates and transmission rates involves three standards set out in the Northwest Power Act. These standards require FERC to confirm and approve these Bonneville rates based on findings that such rates: (1) are sufficient to assure repayment of the federal investment in the Federal System over a reasonable number of years after first meeting Bonneville's other costs; (2) are based on Bonneville's total system costs; and (3) insofar as transmission rates are concerned, equitably allocate the costs of the federal transmission system between federal and non-federal power utilizing such system. FERC does not, however, review Bonneville's rate design or the cost allocation for rates for firm power and Regional non-firm energy. For a discussion of FERC regulations related to transmission access and rates, see "TRANSMISSION BUSINESS LINE—Non-discriminatory Transmission Access and Separation of the Business Lines."

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

Upon reviewing Bonneville's rates, FERC may either confirm or reject a rate proposed by Bonneville. FERC lacks the authority to establish a rate in lieu of a proposed rate that FERC finds does not meet the applicable standards. In the opinion of Bonneville's General Counsel, if FERC were to reject a proposed Bonneville rate, FERC would be limited to remanding the proposed rate to Bonneville for further proceedings as Bonneville deems appropriate. On remand, Bonneville would have to reformulate the proposed rate to comply with the statutory ratemaking standards. If FERC were to have given Bonneville interim approval, Bonneville may be required to refund the difference between the interim rate charged and any such final, FERC-approved rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Judicial Review of Federal Energy Regulatory Commission Final Decision

FERC's final approval of a proposed Bonneville rate is a final action subject to direct, exclusive review by the Ninth Circuit Court. Suits challenging final actions must be filed within 90 days of the time such action is deemed final. The record upon review by the court is limited to the administrative record compiled in accordance with the Northwest Power Act.

Unlike FERC, the court reviews all of Bonneville's ratemaking for conformance with all Northwest Power Act standards, including those ratemaking standards incorporated by reference in the Northwest Power Act. In the opinion of Bonneville's General Counsel, the court lacks the authority to establish a Bonneville rate. Upon review, the court may either affirm or remand a rate to FERC or Bonneville, as appropriate. On remand, Bonneville would have to reformulate the remanded rate. Bonneville's flexibility in establishing rates could be restricted by the rejection of a Bonneville rate, depending on the grounds for the rejection. Bonneville may be subject to refund obligations if the reformulated rate were lower than the remanded rate. However, Bonneville is required by law to set rates to meet all its costs; thus, it is the opinion of Bonneville's General Counsel that Bonneville may be required to increase its rates to seek to recover the amount of any such refunds, if needed.

Power Customer Classes. The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (1) to public and certain federal agency customers; (2) to direct service industrial customers; and (3) for those portions of their load which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Residential Exchange Program." The rates for power sold to these respective customers classes are based on allocation of the costs of the various resources available to Bonneville, consistent with the various statutory directives contained in Bonneville's organic statutes.

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

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

Limitations on Suits Against Bonneville

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

Laws Relating to Environmental Protection

Bonneville must comply with the National Environmental Policy Act ("NEPA"), which requires that federal agencies conduct an environmental review of a proposed federal action and prepare an environmental impact statement if the action proposed may significantly affect the quality of the human environment. NEPA may require that Bonneville follow statutory procedures prior to deciding whether to implement an action. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Toxic Substance Control Act ("TSCA") and applicable state statutes and regulations, as well as amendments thereto, may result in Bonneville incurring unplanned costs to investigate and clean up sites where hazardous substances have been released or disposed of. There are currently 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 the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River Basin for the purposes of power generation and flood control.

Regulation of stream flows by the Canadian reservoirs enables six federal and five non-federal dams downstream in the United States to generate more usable, firm electric power. This increase in firm power is referred to as the "downstream power benefits." The Treaty specifies that the downstream power benefits be shared equally between the two countries. Canada's portion of the downstream power benefits is known as the "Canadian Entitlement."

The Treaty specifies that the Canadian Entitlement be delivered to Canada at a point on the border near Oliver, British Columbia, unless the United States Entity and the Canadian Entity agree to other arrangements. The United States Entity and Canadian Entity signed the "Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 15, 2024" (the "Entity Agreement") on November 20, 1996, which was subsequently revised on March 29, 1999. As a result, the United States Entity does not have to build the proposed transmission line to a point near Oliver, British Columbia, in order to return the Canadian Entitlement.

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

Proposals for Federal Legislation and Administrative Action Relating to Bonneville

Congress from time to time considers legislative changes that could affect electric power markets generally and Bonneville specifically. For example, several bills have proposed, among other things, granting buyers and sellers of power access to Bonneville's transmission under 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 its current transmission rate authority under which Bonneville would, if necessary, be required to use transmission rates to recover its power function costs. Other proposals advanced in Congress have included privatizing the federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at federal hydroelectric projects, requiring that Bonneville sell its power at auctioned market prices rather than under cost-based rates and submitting Bonneville's power marketing to varying degrees of FERC regulation. None of these bills or proposals were enacted into law.

On February 2, 2005, President Bush issued the budget for Federal Government for fiscal year 2006. The President's Fiscal Year 2006 Budget includes a proposal for legislation that calls "for certain nontraditional financing transactions that are entered into after the date the legislation is enacted and that are similar to debt-like transactions to be treated as debt and counted toward [Bonneville's] statutory debt limit." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Nonetheless, the budget provides that the proposal would only affect those transactions occurring after enactment of the legislation. In addition, the Department of Energy has agreed that the proposed legislation will not affect Bonneville's ability to participate in the refinancing of debt it secures pursuant to transactions that Bonneville entered into prior to the date the proposed legislation takes effect.

The President's Fiscal Year 2006 Budget also includes a proposal for legislation "to very gradually bring [the federal power marketing administrations', including Bonneville's] electricity rates closer to average market rates throughout the country." The administration has not yet sought to introduce draft legislation to effect this proposal in Congress, thus, the exact nature of the proposal is uncertain. Bonneville is unable to predict whether such legislation will be introduced in, or enacted into law by, Congress.

Bonneville cannot predict whether these or any other proposals relating to it will be enacted. Nor can Bonneville predict the terms any such future proposals or laws may include. It is possible that such future proposals, if enacted, could affect Bonneville's ability to perform its obligations with respect to the Series 2005 Bonds.

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

BONNEVILLE FINANCIAL OPERATIONS

The Bonneville Fund

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

All receipts, collections and recoveries of Bonneville in cash from all sources are now deposited in the Bonneville Fund. These include revenues from the sale of power and other services, trust funds, proceeds from the sale of bonds by

Bonneville to the United States Treasury, any appropriations by Congress for the Bonneville Fund, and any other Bonneville cash receipts.

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

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

No prior budget submittal, appropriation, or any prior Congressional action is required to create such obligations except in certain specified instances. These include construction of transmission facilities outside the Northwest, construction of major transmission facilities within the Northwest, construction of certain fish and wildlife facilities, condemnation of operating transmission facilities and acquisition of a major resource that is not consistent with the Power Plan.

The Federal System Investment

The total cost of the multipurpose Corps and Bureau projects is allocated among the purposes served by the projects, which may include flood control, navigation, irrigation, municipal and industrial water supply, recreation, the protection, mitigation and enhancement of fish and wildlife, and the generation of power. The costs allocated to power generation from the Corps and Bureau projects as well as the cost of the transmission system prior to 1974 have been funded through appropriations. The capital costs of the transmission system since 1974 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, 2004, Bonneville had repaid $6.6 billion of principal of the Federal System investment and has $4.4 billion principal amount outstanding with regard to such appropriated investments.

Bonneville Borrowing Authority

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

Of the $4.45 billion in borrowing authority that Bonneville has with the United States Treasury, $2.90 billion of bonds were outstanding as of September 30, 2004. 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, 2004, the interest rates on the outstanding bonds ranged from 2.30% to 8.55% with a weighted average interest rate of approximately 4.87%. The original terms of the outstanding bonds vary from 3 to 40 years. The term of the bonds is limited by the average expected service life of the associated investment: 40 years for transmission facilities, 75 years for Corps and Bureau capital investments, 20 years for conservation investments and 15 years for fish and wildlife projects. Bonds can be issued with 5-year call options. As of September 30, 2004, Bonneville had four callable bonds on its books totaling $228.9 million.

Debt Optimization Proposal

In the spring of 2000, Bonneville presented a "Debt Optimization Proposal" (or "Bonneville Proposal") to Energy Northwest. The proposal, which was agreed to by Energy Northwest, involves the extension of the final maturity of debt issued for the Columbia Generating Station. 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 for any future refinancing of such bonds.

Bonneville manages its overall debt portfolio to meet the objectives of: (1) minimizing the cost of debt to Bonneville's rate payers; (2) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs at the lowest cost to rate payers; and (3) maintaining sufficient financial flexibility to handle Bonneville's financial requirements. Implementing the proposal is intended to provide Bonneville with cash flow flexibility in funding planned capital expenditures, allow Bonneville to advance the amortization of Bonneville's high interest Federal debt and reduce Bonneville's overall fixed costs. Under the Debt Optimization Proposal through July 1, 2004, approximately $1 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 refinancings through at least fiscal year 2008. See "PURPOSE OF ISSUANCE" 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. 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 is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (ii) debt service on bonds issued by Bonneville and sold to the United States Treasury; (iii) repayment of appropriated amounts to the Corps and the Bureau for costs that are allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its fiscal year 2004 payment responsibility to the United States Treasury in full and on time. Of Bonneville's payments of $1.053 billion in fiscal year 2004, approximately $346 million were for the amortization ahead of schedule of certain outstanding bonds issued by Bonneville to the United States Treasury. This advance amortization was achieved in accordance with Bonneville's Debt Optimization Proposal through the use of cash flows derived from reduced debt service in such fiscal year for the Project 1, Project 3 and the Columbia Generating Station. Such Treasury prepayments were payments in addition to the amounts that United States Treasury repayment criteria applicable to Bonneville ratemaking would cause to be scheduled for payment. In accordance with the Debt Optimization Proposal, Bonneville plans to make similar advance amortization payments to the United States Treasury in fiscal year 2005 and in subsequent fiscal years. See "—Debt Optimization Proposal."

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2005 Bonds, payments, if any, under the 1989 Letter Agreement 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 under the Net Billing Agreements securing the Series

2005 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.

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

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

Under the repayment methodology as specified in the United States Secretary of Energy's directive RA 6120.2, amortization of the Federal System investment is paid after all other cash obligations have been met. If, in any year, Bonneville has insufficient cash to make a scheduled amortization payment, Bonneville must reschedule amortization payments not made in that year over the remaining repayment period. If a cash under-recovery were larger than the amount of planned amortization payments, Bonneville would first reschedule planned amortization payments and then defer current interest payments to the United States Treasury. When Bonneville defers an interest payment, the deferred amount is assigned a market interest rate determined by the Secretary of the United States Treasury and must be repaid before Bonneville 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.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both the Bureau and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Bureau federal system operations and maintenance activities. Bonneville's expenses for the Corps, Bureau, and the Fish and Wildlife Service in fiscal year 2004 were $60 million for the Bureau, $138 million for the Corps, and $17 million for the Fish and Wildlife Service.

Bonneville believes that, in contrast to prior practice, the direct payment approach increases Bonneville's influence on the Corps' and the Department of Interior's Federal System operations and maintenance activities, expenses and budgets because, in general, Bonneville's approval becomes necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct payments would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct payments could be made to the exclusion of non-federal payments that would otherwise have been paid under historical practice. A result of any direct payment obligation by Bonneville is that there would be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, during the terms of the direct payment agreements, Bonneville expects to have roughly $500 to $800 million in scheduled annual payments to the United States Treasury, exclusive of the Corps' and the Department of Interior's operation and maintenance expenses.

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 is not planning to make any such early appropriations repayments in fiscal year 2005.

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, Bureau and certain other expenses see "—Direct Funding of Federal System Operations and Maintenance Expense."

Hedging and Derivative Instrument Activities and Policies

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

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

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

In January 2003, Bonneville entered into two floating to fixed interest rate swap agreements with an aggregate notional amount of $500 million. The swap agreements were entered into in connection with, and are in an aggregate notional principal amount approximately equal to, the principal amount of certain variable rate 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 2002 through 2004 are hereinafter set forth in the Federal System Statement of Revenues and Expenses. This information has been derived from the annual audited financial statements of the Federal System and should be read in conjunction with Appendix B-1. Federal System financial statements are prepared in conformity with generally accepted accounting principles. The audited Financial Statements of the Federal System (which include accounts of Bonneville as well as those of the generating facilities of the Corps and the Bureau for which Bonneville is the power marketing agency) for the fiscal year ended September 30, 2004 are included as Appendix B-1 to the Official Statement. The unaudited quarterly financial report for the six months ended March 31, 2005 is included as Appendix B-2.

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

Fiscal year ending September 30,	2004	2003	2002
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-owned utilities (1)	$ 1,737,895	$ 1,723,341	$ 1,798,477
Direct Service Industrial Customers	92,424	18,494	58,466
Northwest Investor-Owned Utilities	363,201	436,702	378,083
Sales outside the Northwest Region (2)	489,063	628,243	638,267
Book-outs (3)	(212,155)	0	0
Total Sales of Electric Power	2,470,428	2,806,780	2,873,293
Transmission (4)	535,936	552,718	566,654
Fish Credits and other revenues (5)	191,547	252,606	93,782
Total Operating Revenues	3,197,911	3,612,104	3,533,729
Operating Expenses:			
BPA O&M (6)	613,121	607,616	775,077
Purchased Power (3)	794,284	1,043,009	1,286,867
Book-outs (3)	(212,155)	0	0
Corps, Bureau and Fish & Wildlife O&M (7)	214,035	198,539	198,055
Non-Federal entities O&M — net billed (8)	221,210	208,535	167,026
Non-Federal entities O&M — non-net billed (9)	37,521	39,864	35,566
Total Operation and Maintenance	1,668,016	2,097,563	2,462,591
Net billed debt service	222,779	104,329	213,919
Non-net billed debt service	25,696	15,205	16,256
Non-Federal Projects Debt Service (10)	248,475	119,534	230,175
Federal Projects Depreciation	366,239	350,025	335,205
Residential Exchange (11)	125,915	143,967	143,983
Total Operating Expenses	2,408,645	2,711,089	3,171,954
Net Operating Revenues	789,266	901,015	361,775
Interest Expense:			
Appropriated Funds	281,607	280,094	325,551
Long-term debt	110,251	166,598	151,997
Capitalization Adjustment (12)	(68,566)	(67,703)	(67,356)
Allowance for funds used during construction	(38,441)	(33,398)	(57,892)
Net Interest Expense	284,851	345,591	352,300
Net Revenues/(Expenses)	$ 504,415	$ 555,424	$ 9,475
Total Sales (unaudited) — average megawatts (Net of Residential Exchange Program)	9,772	10,764	11,732

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

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

(3) Total operating expenses and revenue from electricity sales reflect recent accounting guidance from the Emerging Issues Task Force ("EITF") of the Financial Accounting Standards Board ("FASB"). Under this new guidance ("EITF 03-11") 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 new guidance thus decreased both operating revenues and purchase power expense by $212 million 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 to its United States Treasury repayment obligation. See "POWER BUSINESS LINE—Certain Statutes and Other Matters Affecting Bonneville's Power Business Line—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville." Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. In addition, under FASB Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), Bonneville also reported unrealized market-to-market gains of $38.4 million, $55.3 million and $89.5 million, in Fiscal Years 2002, 2003 and 2004, respectively.

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

(8) The nonfederal 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.

(9) The nonfederal 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 2004. Bonneville had net revenues of $504 million in fiscal year 2004, a decrease of approximately $51 million from fiscal year 2003. The Debt Optimization Program and other debt management actions contributed significantly to sustaining positive net revenues. Without 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 Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standard No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), net revenues would have been $66 million in fiscal year 2004. Under SFAS 133, Bonneville reported an unrealized gain of $89.5 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 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 11%, due to lower total power sales, reduced United States Treasury repayment credits for fish mitigation under section 4(h)(10)(C) of the Northwest Power Act, 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 $73 million, a 17% decrease, and decreased sales outside the Region of $139 million, a 22% 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 1% increase, and to DSI customers of $74 million, or a 400% 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 was 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 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 purchase contract expirations and restructurings also reduced purchase power expense. As described above, application of new accounting guidance decreased reported revenues.

United States Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act, 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. 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%, largely due to decreased Purchase Power in fiscal year 2004. Purchase Power decreased by $461 million, or by about 44%, 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.

Debt service for Non-Federal Projects 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 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.

For further information on fiscal year 2004 financial results, see "DEVELOPMENTS RELATING TO BONNEVILLE'S POWER MARKETING APPROACH AND BONNEVILLE'S FINANCIAL CONDITION—Bonneville's Fiscal Year 2004 Financial Results."

Fiscal Year 2003. Bonneville had net revenues of $555 million in fiscal year 2003, an increase of approximately $546 million over fiscal year 2002. Implementation of the Debt Optimization Proposal and other debt management actions contributed significantly to the substantial increase in net revenues. Without the program, other debt management actions, and the effects of SFAS 133, net revenues would have been $37 million for fiscal year 2003. Total operating revenues in fiscal year 2003 increased by $78 million, or 2%, from the previous fiscal year because of greater sales to Regional IOUs and increased United States Treasury credits derived under section 4(h)(10)(C) of the Northwest Power Act for fish mitigation, even though there was both reduced hydro generation and reduced power sales when compared to fiscal year 2002. However, the average price for discretionary surplus power sales rose from $26 per megawatt hour to $37 per megawatt hour, an increase of 42%. United States Treasury credits under section 4(h)(10)(C) of the Northwest Power Act increased from $38 million to $175 million in 2003. Credits for fish mitigation increased due to below-average water conditions and increased power purchases that result from reduced hydro supply. For a description of 4(h)(10)(C) see "—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

Total operating expenses in fiscal year 2003 were approximately $461 million lower as compared to fiscal year 2002, a decrease of about 15%. This was largely due to decreased Non-Federal Projects Debt Service, which decreased by $111 million or 48% because of the deferral of some principal payments due in fiscal year 2003 into the future, primarily as a result of continued implementation of the Debt Optimization Proposal. Lower interest rates through refinancing some of the Non-Federal debt also contributed to the decline in debt service. Net Interest Expense on Federal debt declined by $7 million compared to fiscal year 2002 due to generally lower interest rates on borrowings from the United States Treasury to finance federal generating and transmission projects. Total operations and maintenance costs, excluding Purchased Power, also decreased by $121 million, or 10% from the previous year. Lower bad debt expense and general and administrative expense were the main factors that led to this decrease. Purchased Power also decreased by $244 million, or 19%, in view of comparatively lower prices for the power purchased by Bonneville and the release of Bonneville from certain power purchase commitments as the result of a settlement between Bonneville and Enron Power Marketing Corp. in its bankruptcy proceedings.

Fiscal Year 2002. In fiscal year 2002, Bonneville had net revenues of $9 million, an increase of approximately $347 million over fiscal year 2001 when Bonneville had net expenses of approximately $337 million.. Total operating revenues declined by $745 million, or 17%, from the previous year due to lower market prices for discretionary sales of surplus power and a 94% decline in fish credits under section 4(h)(10)(C) of the Northwest Power Act. These lower market prices resulted in a decrease of $446 million, or 41%, in revenues from sales outside the Northwest. In addition, revenues from aluminum company DSIs decreased by $362 million, or 86%, largely due to the purchase back by Bonneville of some of its power sales to such DSIs and curtailments of purchases by some DSIs. The $323 million, or 46%, decline in revenues from Regional IOUs in fiscal year 2002 stemmed largely from payments arising under agreements between Bonneville and the Regional IOUs to settle Bonneville's Residential Exchange obligations and the purchase back by Bonneville of some of its power sales to Regional IOUs. This decline in revenues was somewhat mitigated by the amount of revenues from sales to publicly-owned utilities, which in fiscal year 2002 increased by $858 million, or 91%, due to a substantial rate increase at the beginning of the new rate period (October 1, 2002), and an increase in the amount of power Bonneville sold to this customer class. The $472 million, or 42%, decline over fiscal year 2001 in revenues from transmission and other related services was the result of lower estimated United States Treasury repayment credits under section 4(h)(10)(C) of the Northwest Power Act as these repayment credits declined by 94% as noted immediately above. Applicable criteria did not permit use of the Contingency Fund whereas $247 million was drawn from the fund, in the form of United States Treasury repayment credits, during fiscal year 2001.

Total operating expenses in fiscal year 2002 were approximately $3.2 billion, a decrease of $944 million, or 23%, when compared to fiscal year 2001. This was largely due to lower market prices for power purchased by Bonneville. Purchased power expense declined by $1 billion, or 44%, in 2002, due to a 15% decrease in the amount of power purchased by Bonneville as water conditions returned to average levels from the historical low levels of the prior fiscal year, as well as a decrease in the average cost of purchased power. In addition, net billed debt service decreased by approximately $237 million, or 53%, due primarily to the refinancing and restructuring of a portion of the outstanding net billed debt. Non-Federal entities O&M-net billed expense declined by $42 million primarily due to reduced operating expense related to the Columbia Generating Station. However, Bonneville operations and maintenance expenses were up by $244 million dollars, or 46%, in fiscal year 2002, primarily due to increased budgets for fish and wildlife, resource conservation management and bad debt expense.

Statement of Non-Federal Project Debt Service Coverage

The Statement of Non-Federal Project Debt Service Coverage and United States Treasury Payments uses the Federal System Statement of Revenue and Expenses to develop a non-federal Project debt service coverage ratio ("Non-Federal Project Debt Service Coverage Ratio"), which demonstrates how many times total non-federal project debt service is covered by net funds available for non-federal Project debt service. Net funds available for non-federal project debt service is defined as total operating revenues less operating expenses (see footnote 9 to the Statement of Non-Federal Project Debt Service Coverage below). Net funds available for non-federal project debt service less total non-federal project debt service yields the amount available for payment to the United States Treasury. This Non-Federal Project Debt Service Coverage Ratio does not reflect the actual priority of payments or distinctions between cash payments and credits under Bonneville's net billing obligations. For a discussion of certain direct payments by Bonneville for Federal System operations and maintenance, which payments reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see "—Direct Funding of Corps and Bureau Federal System Operations and Maintenance Expense."

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

Fiscal Years ending September 30,	2004	2003	2002
Total Operating Revenues	$3,197,911	$3,612,104	$ 3,533,729
Less: Operating Expense[(1)]	1,579,896	2,042,991	2,408,520
Net Funds Available for Non-Federal Project Debt Service	1,618,015	1,569,113	1,125,209
Less: Total Non-Federal Project Debt Service[(2)]	248,475	119,534	230,175
Revenue Available for Treasury	1,369,540	1,449,579	895,034
Amount Paid to Treasury:			
Corps and Bureau O&M[(3)]	214,035	198,539	198,055
Net Interest Expense[(4)]	284,851	345,591	352,300
Capitalization Adjustment[(5)]	68,566	67,703	67,356
Allowance for Funds Used During Construction[(4) (6)]	21,584	18,641	15,061
Amortization of Principal	592,500	543,747	505,012
Total Amount Allocated for Payment to Treasury[(7)]	1,181,536	1,174,221	1,137,784
Revenues Available for Other Purposes[(8)]	188,004	275,358	(242,750)
Non-Federal Project Debt Service Coverage Ratio[(9)]	6.5	13.1	4.9
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[(10)]	1.7	1.7	1.3

(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 Bureau. Treatment of the Corps, Bureau 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 $16.3 million, $15.2 million and $25.7 million for fiscal years 2002, 2003 and 2004, respectively.

(3) Amounts shown are calculated on an accrual basis and include direct operations and maintenance payments to the Corps, Bureau and Fish & Wildlife for fiscal years 2002, 2003 and 2004. 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 2002, 2003 and 2004 were $1.056 billion, $1.057 billion and $1.053 billion, respectively. In fiscal years 2002, 2003 and 2004, respectively, direct payments to the Corps, Bureau and Fish & Wildlife for operations and maintenance were included in the amount of (i) $132 million, $129 million and $138 million for the Corps, (ii) $51 million, $54 million and $60 million for the Bureau, and (iii) $15 million, $15 million and $17 million for Fish & Wildlife, respectively. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(8) Revenues Available For Other Purposes approximates the change in reserves from year to year. Reserves were $625 million at the end of fiscal year 2001 (not depicted) and $638 million at the end of fiscal year 2004.

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

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

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

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

Statement of Net Billing Obligations and Expenditures (unaudited)[1]
(Actual Dollars in Thousands)

Fiscal years ending September 30,	2004	2003	2002
Operating Revenues from Publicly-Owned Utilities[2]	$ 1,737,895	$ 1,723,341	$1,798,477
Net Billing Obligations:			
Net Billing Credits	508,618	476,947	610,180
Payments in Lieu of Net Billing[3]	(21,395)	(140,261)	(111,329)
Net Billing Obligations — Cash	487,327	336,686	498,851
Net Billing Expenditures:			
Net Billed Debt Service	222,779	104,329	213,919
Other Entities O&M — Net Billed	221,210	208,535	167,026
Increase/(Decrease) in Prepaid Expense	43,338	23,822	117,906
Net Billing Expenditures — Accrual	$ 487,327	$ 336,686	$ 498,851

(1) Bonneville funds its obligation for net billed projects (*i.e.*, the Eugene Water and Electric Board’s (“EWEB”) 30 percent ownership share of the Trojan Nuclear Project and Energy Northwest’s Project 1, Project 3 and Columbia Generating Station) costs on a cash basis and it expenses the net billed project budgets on an accrual basis. This reconciliation ties the cash net billing obligation to the accrual net billing obligation through the changes in Bonneville’s prepaid expense.

(2) Bonneville’s actual revenues from Publicly-Owned Utilities exceeded net billing obligations. Most Publicly-Owned Utilities are Participants in the net billed projects.

(3) Includes voluntary direct cash payments made to Energy Northwest 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 et 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 LITIGATION

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.

PGET Bankruptcy

In July 2003, PG&E Energy Trading – Power L.P. ("PGET"), a non-utility power marketer and affiliate of PG&E, which in turn is a California utility, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Maryland. As a result, Bonneville has notified PGET that Bonneville has terminated all power sales and purchase transactions with PGET. Bonneville also notified PGET of Bonneville's calculation of a termination payment owed by PGET to Bonneville in the amount of approximately $24 million. On June 8, 2004, PGET and Bonneville executed a settlement agreement in which PGET agreed that it would not dispute a Bonneville claim in the amount of $21.8 million. Apart from relatively small dollar amounts relating to two short term power transactions, undelivered power by PGET, and accounts receivable owing to Bonneville at the time of filing, virtually all of the termination payment calculated by Bonneville is attributable to the mark-to-market value of a single 100 megawatt Augmentation Purchase by Bonneville. At the time of Bonneville's notification of termination, there were approximately three years of remaining performance under the Augmentation Purchase. Bonneville is unable to predict whether or the extent to which it will receive any payment on its undisputed unsecured claim.

Longview Aluminum Bankruptcy

On January 28, 2003, Bonneville notified Longview Aluminum, LLC ("Longview") that Bonneville has terminated Longview's 280 average megawatt take-or-pay power sales contract because of nonpayment by Longview. Bonneville estimates that Longview is approximately $17 million in arrears in its payments under the contract and owes Bonneville approximately $3 million for accounts receivable and about $29 million for the forward value of the contract, which is based on the mark-to-market value of remaining sales as of the date of termination. Longview also has an unpaid $1.2 million payment obligation to Bonneville under a long-term transmission service agreement. In addition, Bonneville has made about $9 million in transmission investments, which Longview would be responsible to pay if it fails to meet its long-term transmission purchase obligation.

In February 2003, Longview Aluminum filed two petitions for review against Bonneville in the Ninth Circuit Court. These petitions have been dismissed with prejudice. On March 4, 2003, Longview filed for bankruptcy protection under the federal bankruptcy laws. Bonneville has filed proofs-of-claim totaling approximately $63 million under power and transmission sales agreements. The Trustee appointed in this case was unsuccessful in his attempts to sell Longview as a going-concern, and has since liquidated virtually all of Longview's assets. Bonneville expects to receive little, if anything, on its unsecured claim.

GNA Bankruptcy

On December 22, 2003, Golden Northwest Aluminum ("GNA"), a holding company that contracts on behalf of two DSIs with Bonneville, filed for bankruptcy protection in the U.S. Bankruptcy Court for the District of Oregon. Bonneville estimated that GNA owed Bonneville approximately $18 million on an unsecured basis for take-or-pay power purchase commitments in fiscal years 2002 and 2003. Bonneville filed a proof of claim in the case for this amount plus an additional $500,000, approximately, for certain transmission related claims. Bonneville has entered into a settlement agreement with GNA regarding certain post-bankruptcy petition claims and Bonneville has recorded reserves with respect to its unpaid claims in an amount it believes is appropriate.

Mirant Bankruptcy

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

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

The court issued an order on November 14, 2003, directing Bonneville to remedy its violations of the automatic stay by immediately taking all actions necessary to withdraw the termination letter, reinstate the terminated contracts and reinstate the parties to the status quo existing before the termination letter was sent. Thus, the effect of the order was that Bonneville was required to pay Mirant $522,014 that Bonneville was holding as collateral from Mirant. Bonneville made this payment under protest and with a reservation of rights to appeal the decision. Bonneville then filed a motion with the court seeking to have the automatic stay lifted. On December 23, 2003, the court denied the motion and held, among other things, that Bonneville was not a "person" under the Bankruptcy Code and therefore was not a "forward contract merchant" under the Bankruptcy Code. Bonneville appealed this order in the United States District Court for the Northern District of Texas. The United States District Court for the Northern District of Texas denied Bonneville's appeal on August 13, 2004. The Department of Justice is appealing certain aspects of the court's order in the Fifth Circuit Court.

One possible implication of the rulings was that Bonneville would be precluded in the future from enjoying certain safe-harbor provisions of the Bankruptcy Code afforded to "forward contract merchants," and that upon a counter-party's bankruptcy, Bonneville would have been precluded by the automatic stay from declaring a default, terminating extant agreements and liquidating all positions, setting off pre-petition mutual debts and claims, and realizing against any collateral held to secure the debtor's obligations under the confirmation agreements. Recent Bankruptcy Code amendments enacted by Congress and signed into law after the Mirant rulings were issued provide that an "entity" under the Bankruptcy Code may qualify as a "forward contract merchant" thereunder, assuming other applicable attributes are met. In the opinion of General Counsel to Bonneville, Bonneville is an "entity" under the Bankruptcy Code.

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 the Period After Fiscal Year 2001—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 $83 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.

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 June 2005. Bonneville and the other Slice litigants have retained a mediator and are attempting to resolve the 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 the Period After Fiscal Year 2001—Subscription Strategy Contracts Opt-Out Provisions." Briefing has been completed and the parties await the scheduling of oral argument.

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.

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 the Period After Fiscal Year 2001."

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

A number of Bonneville's customers and customer groups filed petitions with the Ninth Circuit Court seeking review of the RPSAs and the Residential Exchange Settlement Agreements 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 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 the Period After Fiscal Year 2001—Residential Exchange Program Obligations."

Several of Bonneville's customers have filed lawsuits in Ninth Circuit Court challenging the June 2004 agreements between Bonneville and the related Regional IOUs.

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 Southern terminating service under its power sales contract due to SCE's nonperformance. All three petitions for review were dismissed by the Ninth Circuit Court for lack of jurisdiction and were transferred to the U.S. Court of Federal Claims. Subsequently, 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.

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.

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 claims have been stayed pending mediated settlement discussions between Bonneville and SCE.

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

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

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. The parties are in the process of preparing briefs.

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 Northwest Power and Conservation 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 stayed pending settlement discussions.

Upper Columbia United Tribes Litigation

On December 18, 2003, the Upper Columbia United Tribes ("UCUT"), as well as certain other tribal petitioners, filed a petition for review in the Ninth Circuit Court challenging a letter from Bonneville to the Council. As with the Yakama Nation Litigation, above, the challenged letter addresses issues related to Bonneville's Fish and Wildlife Funding. The UCUT litigation is related to the Yakama Nation litigation, described above, and has been selected for inclusion in the Ninth Circuit Court's mediation program. Bonneville and the UCUT petitioners are currently engaged in settlement discussions, and the case is stayed pending such discussions.

ESA Litigation

National Wildlife Federation v. National Marine Fisheries Service

In a lawsuit filed May 4, 2001, in the United States District Court for the District of Oregon, the National Wildlife Federation and other plaintiffs asked the court: (1) to declare that the 2000 Biological Opinion and incidental take statement are arbitrary and capricious, an abuse of discretion, and otherwise not in accordance with law, and (2) to order NMFS (now known as "NOAA Fisheries") to reinitiate consultation with the action agencies responsible for operation of the Federal System hydroelectric projects—the Corps, the Bureau, and Bonneville (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 is inadequate because it relies on offsite mitigation measures that are "not reasonably certain to occur."

In June 2003, the court remanded the 2000 Biological Opinion back to NOAA Fisheries to correct the deficiencies identified by the court.

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 have filed a complaint against NOAA Fisheries with the District Court, alleging that the 2004 Biological Opinion violates certain provisions of the ESA. The judge in the proceedings has stated that he intends to issue a ruling on the merits of the case in early May of 2005. Notwithstanding the foregoing statement, the court has not issued a ruling on this matter as of the date of the Official Statement. In view of the range of possible outcomes of the litigation and the possible consequences arising therefrom, Bonneville is unable to predict the additional costs to Bonneville of an adverse ruling.

Additionally, plaintiffs have filed an application for a preliminary and/or permanent injunction against the Corps and Bureau with respect to Federal System dam operations. The application for injunction seeks an order for, among other things, certain increased spill and a ten percent increase in river velocity this fiscal year. Bonneville has filed a statement with the court estimating that the cost of such an operation would likely be about $102 million in forgone revenues in fiscal years 2005 and 2006. The effects in fiscal year 2006 would arise because the requested operation would have carryover effects on reservoir levels for fiscal year 2006. No date has yet been set for a hearing on the preliminary/permanent injunction.

Alsea Valley Alliance v. Evans

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

After this decision, a number of intervener environmental groups appealed the decision to the Ninth Circuit Court. These groups successfully stayed the findings of the district court. The effect of the stay was to temporarily re-list the Oregon Coast Coho pending the decision on appeal. In addition to the appeal, NOAA Fisheries received 14 additional petitions from various interest groups to de-list other salmon populations. As a result, NOAA Fisheries decided to revisit its Hatchery Listing Policy.

In February 2004, the Ninth Circuit Court rejected the intervener environmental groups' motion to reinstate the Oregon Coast Coho as a listed species and upheld the District Court's invalidation of the listing decision. Thus, the Oregon Coast Coho was de-listed under the ESA. In June 2004, NOAA Fisheries published a proposed new hatchery policy and a proposed rule for the listing of 25 salmon and salmon-related populations, all but one of which had previously been listed. The proposed rule would re-list the Oregon Coast Coho salmon and would list the Lower Columbia Coho salmon for the first time. The other 23 populations would remain listed as either endangered or threatened, representing no change from current status. NOAA Fisheries must make a final decision on a proposed listing rule by June 14, 2005, and it has stated that it expects to issue a final hatchery policy shortly prior to that date.

Rates Litigation

Bonneville's rates are frequently the subject of litigation. Most of the litigation involves claims that Bonneville's rates are inconsistent with statutory directives, are not supported by substantial evidence in the record or are arbitrary and capricious. Bonneville proposed new power rates for the five years beginning October 1, 2001, which were subsequently approved by FERC in July 2003. Bonneville also proposed an SN-CRAC rate level adjustment, which was reviewed and approved by FERC. Bonneville has proposed transmission rates for the two years beginning October 1, 2003. See "POWER BUSINESS LINE—Power Marketing in the Period After Fiscal Year 2001," "TRANSMISSION BUSINESS LINE—Bonneville's Transmission and Ancillary 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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Report of Independent Auditors

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, 2004 and 2003, and the results of its operations and its cash flows for the three years in the period ended September 30, 2004, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2004, 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.

As discussed in Note 1 of the financial statements, FCRPS changed the manner in which it accounts for realized gains and losses on the settled derivative contracts not held for trading purposes, as of October 1, 2003.

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The Schedule of Amount and Allocation of Plant Investment as of September 30, 2004 (Schedule A) and the Schedule of Revenues and Expenses for each of the three years in the period ended September 30, 2004 (Schedule B) are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
October 28, 2004

Financial Statements

Combined Statements of Revenues and Expenses

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

	2004	2003	2002
Operating revenues			
Sales	**$2,973,496**	$ 3,328,277	$ 3,407,404
SFAS 133 mark-to-market	**89,452**	55,265	38,354
Miscellaneous revenues	**57,963**	53,678	49,571
U.S. Treasury credits for fish	**77,000**	174,884	38,400
Total operating revenues	**3,197,911**	3,612,104	3,533,729
Operating expenses			
Operations and maintenance	**1,211,802**	1,198,521	1,319,707
Purchased power	**582,129**	1,043,009	1,286,867
Nonfederal projects	**248,475**	119,534	230,175
Federal projects depreciation	**366,239**	350,025	335,205
Total operating expenses	**2,408,645**	2,711,089	3,171,954
Net operating revenues	**789,266**	901,015	361,775
Interest expense			
Interest on federal investment:			
Appropriated funds	**213,041**	212,391	258,195
Bonds issued to U.S. Treasury	**110,251**	166,598	151,997
Allowance for funds used during construction	**(38,441)**	(33,398)	(57,892)
Net interest expense	**284,851**	345,591	352,300
Net revenues	**504,415**	555,424	9,475
Accumulated net revenues (expenses), Oct. 1	**343,748**	(211,676)	(221,151)
Irrigation assistance	**(739)**	—	—
Accumulated net revenues (expenses), Sept. 30	**$ 847,424**	$ 343,748	$ (211,676)

The accompanying notes are an integral part of these statements.

Combined Balance Sheets

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

Assets

	2004	2003
Utility plant		
Completed plant	**$ 12,243,684**	$ 11,873,798
Accumulated depreciation	**(4,357,496)**	(4,133,886)
	7,886,188	7,739,912
Construction work in progress	**1,401,793**	1,308,624
Net utility plant	**9,287,981**	9,048,536
Nonfederal projects		
Conservation	**43,566**	47,246
Hydro	**146,210**	146,210
Nuclear	**2,222,104**	2,181,182
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,894,273**	3,883,115
Total nonfederal projects	**6,334,243**	6,286,593
Decommissioning cost	**164,000**	126,000
IOU exchange benefits	**606,539**	—
Conservation, net of accumulated amortization of $946,322 in 2004 and $892,218 in 2003	**337,355**	374,443
Fish and wildlife, net of accumulated amortization of $142,465 in 2004 and $133,743 in 2003	**116,910**	128,337
Current assets		
Cash	**654,242**	503,026
Accounts receivable, net of allowance	**91,517**	146,768
Accrued unbilled revenues	**158,074**	190,416
Materials and supplies, at average cost	**81,246**	84,306
Prepaid expenses	**331,383**	288,068
IOU exchange benefits	**381,720**	—
Total current assets	**1,698,182**	1,212,584
Other assets	**387,569**	230,756
	$ 18,932,779	$ 17,407,249

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2004	2003
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 847,424**	$ 343,748
Federal appropriations	**4,339,288**	4,607,476
Capitalization adjustment	**2,056,131**	2,124,697
Bonds issued to U.S. Treasury	**2,461,800**	2,521,554
Nonfederal projects debt	**6,218,932**	6,045,931
Decommissioning reserve	**164,000**	126,000
IOU exchange benefits	**626,576**	55,488
Accrued plant removal costs	**105,270**	147,174
Total capitalization and long-term liabilities	**16,819,421**	15,972,068
Commitments and contingencies (Notes 7 and 8)		
Current liabilities		
Current portion of federal appropriations	**104,673**	73,484
Current portion of bonds issued to U.S. Treasury	**438,500**	176,200
Current portion of nonfederal projects debt	**234,896**	240,662
Current portion of IOU exchange benefits	**381,720**	—
Accounts payable and other current liabilities	**338,867**	369,821
Total current liabilities	**1,498,656**	860,167
Deferred credits	**614,702**	575,014
	$18,932,779	$17,407,249

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	Federal Appropriations	Bonds Issued to Treasury	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2002	$ (211,676)	$ 4,642,602	$ 2,770,441	$ 6,201,544	$ 2,407,238	$15,810,149
Increase in federal appropriations for construction	—	99,418	—	—	—	99,418
Repayment of federal appropriations for construction	—	(61,060)	—	—	—	(61,060)
Capitalization adjustment amortization	—	—	—	—	(67,703)	(67,703)
Increase in bonds issued to U.S. Treasury	—	—	470,000	—	—	470,000
Repayment of bonds issued to U.S. Treasury	—	—	(482,687)	—	—	(482,687)
Refinance of bonds issued to U.S. Treasury	—	—	(60,000)	—	—	(60,000)
Net increase in nonfederal projects debt	—	—	—	99,288	—	99,288
Repayment of nonfederal projects debt	—	—	—	(14,239)	—	(14,239)
Decommissioning reserve	—	—	—	—	52,139	52,139
IOU exchange benefits	—	—	—	—	55,488	55,488
Accrued plant removal costs	—	—	—	—	6,197	6,197
Net revenues	555,424	—	—	—	—	555,424
Balance at Sept. 30, 2003	$ 343,748	$ 4,680,960	$ 2,697,754	$ 6,286,593	$ 2,453,359	$ 16,462,414
Increase in federal appropriations for construction	—	78,047	—	—	—	78,047
Repayment of federal appropriations for construction	—	(315,046)	—	—	—	(315,046)
Capitalization adjustment amortization	—	—	—	—	(68,566)	(68,566)
Increase in bonds issued to U.S. Treasury	—	—	480,000	—	—	480,000
Repayment of bonds issued to U.S. Treasury	—	—	(277,454)	—	—	(277,454)
Net increase in nonfederal projects debt	—	—	—	179,130	—	179,130
Repayment of nonfederal projects debt	—	—	—	(11,895)	—	(11,895)
Decommissioning reserve	—	—	—	—	38,000	38,000
IOU exchange benefits	—	—	—	—	952,808	952,808
Accrued plant removal costs	—	—	—	—	(41,904)	(41,904)
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	$ 3,333,697	$17,979,210

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

	2004	2003	2002
Cash from operating activities			
Net revenues	$ 504,415	$555,424	$ 9,475
Non-cash items:			
Depreciation	294,975	269,957	254,332
Amortization	71,264	77,610	78,047
Amortization of capitalization adjustment	(68,566)	(67,703)	(67,356)
Decrease (increase) in:			
Receivables and unbilled revenues	87,594	(38,144)	88,765
Materials and supplies	3,061	801	115
Prepaid expenses	(43,316)	(2,372)	(98,547)
Decrease (increase) in:			
Accounts payable and other current liabilities	(30,954)	26,396	(167,532)
Other	(152,601)	51,802	(6,399)
Cash provided by operating activities	665,872	873,771	90,900
Cash from investment activities			
Investment in:			
Utility plant (including AFUDC)	(576,324)	(535,211)	(544,922)
Nonfederal projects	(47,650)	(85,050)	(29,595)
Conservation	(16,876)	(25,458)	(25,344)
Fish and wildlife	(5,849)	(11,156)	(6,102)
Cash used for investment activities	(646,699)	(656,875)	(605,963)
Cash from borrowing and appropriations			
Increase in federal construction appropriations	78,047	99,418	168,583
Repayment of federal construction appropriations	(315,046)	(61,060)	(196,911)
Irrigation assistance	(739)	—	—
Increase in bonds issued to U.S. Treasury	480,000	470,000	390,000
Repayment of bonds issued to U.S. Treasury	(277,454)	(482,687)	(308,101)
Refinance of bonds issued to U.S. Treasury	—	(60,000)	—
Increase in nonfederal debt, net	167,235	85,050	29,595
Cash provided by borrowing and appropriations	132,043	50,721	83,166
Increase (decrease) in cash	151,216	267,617	(431,897)
Beginning cash balance	503,026	235,409	667,306
Ending cash balance	$ 654,242	$503,026	$235,409

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of General Accounting Policies

Principles of Combination

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

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

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51," which clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. As a Variable Interest Entity, Northwest Infrastructure Financing Corporation (NIFC) has been consolidated into BPA for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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 2002 and 2003 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2004. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

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

BPA submitted to FERC a Power Rate Filing in fiscal year 2001 for fiscal years 2002 through 2006, and a Transmission and Ancillary Services Rate Filing in fiscal year 2003 for fiscal years 2004 through 2005. FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001) and granted final approval on July 21, 2003, 104 FERC 61,093 (2003). FERC granted final approval of BPA's Transmission and Ancillary Services rates on Sept. 23, 2003, 104 FERC 62,207 (2003).

BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three CRACs, each triggered by a different set of conditions. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The LB CRAC percentage changes every six months. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of modified accumulated net revenues is below a predetermined threshold. The third is the Safety Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or forecasts a 50 percent or greater probability of missing a payment to the Treasury or another creditor. Some of these rate adjustment clauses are calculated initially on forward-looking estimates of market conditions, and adjustments are made after the fact when actual conditions are known. These subsequent adjustments result in an additional charge or rebate due to customers for any excess or shortfall of amounts initially charged to them.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46.0 percent for the first half of fiscal year 2002 compared to base rates, and 40.8 percent for the second half of fiscal year 2002. The LB CRAC percentage increase was revised to 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 August 2002 forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a rate increase of approximately 11 percent for fiscal year 2003 and approximately 12 percent for fiscal year 2004 for most of the requirements rates on top of the revised levels of the LB CRAC.

The SN CRAC did not trigger in fiscal year 2002 but did trigger in fiscal year 2003, requiring an expedited rate case and resulting in a rate increase that went into effect Oct. 1, 2003 through Sept. 30, 2004, of approximately 10 percent on top of the revised levels of the LB CRAC and FB CRAC. BPA submitted to FERC a separate power rate filing for SN CRAC in fiscal year 2003. FERC granted interim approval of the SN CRAC rate on Oct. 1, 2003, 105 FERC 61,006 (2003) and final approval 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.

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 to be paid in fiscal year 2004. For the fiscal year 2004 settlement, BPA recognized a receivable of $10.1 million to be received in fiscal year 2005.

SFAS 71 Assets

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

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

If BPA were to discontinue using SFAS 71 it would simultaneously write down the SFAS 71 assets and amortize the remaining Appropriations Capitalization Adjustment resulting in a $3.6 billion net extraordinary loss that would be reported in the Statement of Revenues and Expenses.

The SFAS 71 assets of $5.6 billion, shown in the following table, reflect an increase of

SFAS 71 Assets

As of Sept. 30 — thousands of dollars

	2004	2003
Nonfederal projects:		
Conservation	**$ 43,566**	$ 47,246
Terminated hydro facilities	**28,090**	28,840
Terminated nuclear facilities	**3,894,273**	3,883,115
Decommissioning cost*	**51,200**	18,200
IOU exchange benefits	**988,259**	—
Conservation	**337,355**	374,443
Fish and wildlife	**116,910**	128,337
Settlements	**70,142**	105,313
Capital bond premiums	**26,486**	30,802
Additional retirement contributions	**13,200**	23,400
	$ 5,569,481	$ 4,639,696

* The decommissioning amount to be collected in future rates is net of amounts paid into the decommissioning trusts of $112.8 million and $107.8 million at Sept. 30, 2004 and 2003 respectively.

$930 million from the prior year. Amortization of these costs aggregating $103 million, $84 million and $299 million in fiscal years 2004, 2003 and 2002 respectively, is reflected in the Statements of Revenues and Expenses. BPA does not earn a rate of return on its SFAS 71 assets.

Utility Plant

Utility plant is stated at original cost. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. The costs of additions, major replacements and betterments are capitalized. Repairs and minor replacements are charged to operating expense. The cost of utility plant retired is charged to accumulated depreciation when it is removed from service. The removal costs less salvage is charged to the regulatory liability. Utility plant in the Statements of Cash Flows is reported net of the Regulatory Liability for Removal Costs and accumulated depreciation.

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 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 certain generating projects and were 1.3 percent to 5.3 percent in fisal year 2004, 1.8 percent to 6.3 percent in fiscal year 2003, and 3.3 percent to 6.5 percent in fiscal year 2002.

Capitalization rates for other construction were approximately 5.3 percent in fiscal year 2004, 6.3 percent in fiscal year 2003, and 6.5 percent in fiscal year 2002. These rates approximate the cost of borrowing from the U.S. Treasury.

Asset Retirement Obligations

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

Regulation

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

Asset Retirement Obligations Activity

As of Sept. 30, 2004, the AROs for Washington Nuclear Project No. 1 (WNP-1), Columbia Generating Station (CGS) and Trojan are $164 million. (See Decommissioning and Restoration Costs in Note 7, Commitments and Contingencies.) A corresponding amount representing a regulatory asset is included in Decommissioning Cost in the Balance Sheet.

The table below presents the effects to the balances and activities in AROs for the accounting periods reported herein. A revision was made in the current year adjusting the accretion rate from the original model and calculation. BPA has funded $112.8 million at Sept. 30, 2004, for these AROs, which is being held in trust. The remaining amount will be collected in future rates.

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and Corps. Cash paid for interest was $420 million, $466 million and $484 million in fiscal years 2004, 2003 and 2002 respectively.

Non-cash transactions include changes in nonfederal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $179 million, $99 million and $259 million in fiscal years 2004, 2003 and 2002 respectively.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist of available-for-sale investments held by Energy Northwest and BPA accounts receivable. Energy Northwest invests exclusively in securities of the U.S. government and agencies.

BPA's accounts receivable 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

Asset Retirement Obligations Activity

For the years ended Sept. 30 — thousands of dollars

	2004	2003	Proforma 2002
Beginning Balance	**$ 126,000**	$129,900	$134,100
Activity:			
Expenditures	**(7,900)**	(7,000)	(9,100)
Accretion	**6,800**	3,100	3,100
Revisions	**39,100**	—	1,800
Ending Balance	**$ 164,000**	$126,000	$129,900

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 2004, BPA experienced no significant losses as a result of any customer defaults or bankruptcy filings.

The Transacting Risk Management Committee is responsible for BPA's credit policy. Credit risk is mitigated at BPA by reviewing counterparties for creditworthiness, establishing credit limits, and monitoring credit exposure. In order to further reduce 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.

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. Defaults by Pacific Gas & Electric (which filed for bankruptcy protection in April 2001) and Southern California Edison (which has established a creditor payment plan) in payments for energy and transmission to the California Independent System Operator (Cal-ISO) resulted in the Cal-ISO not paying its suppliers. In addition, the California Power Exchange (Cal-PX) has substantial outstanding payment obligations due from the California investor-owned utilities for day-ahead power exchanges. The Cal-PX filed for bankruptcy protection in March 2001.

BPA entered into certain power sales during fiscal year 2001 through the Cal-PX for which BPA has not yet been paid. In addition BPA sold power and related services to the Cal-ISO during fiscal year 2001 for which BPA has not yet been paid in full. BPA has recorded provisions for uncollectible receivables and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, BPA is continuing to pursue collection of amounts due in bankruptcy and other proceedings. Net exposure after the reserve is not significant.

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, agency retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is equivalent to 10.7 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS. 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.

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 amount has been recorded as an SFAS 71 asset. FCRPS has a $13.2 million remaining liability as of Sept. 30, 2004, 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 year's additional contributions are made. FCRPS expects to satisfy its prior year commitments for under funded post-retirement benefits by fiscal year 2007.

Deferred Credits

Advances on customer reimbursable projects are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or are recorded to revenue over the related useful lives of the assets if BPA retains title.

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

Derivative/SFAS 133 mark-to-market represents unrealized losses on derivatives. It increased in fiscal year 2004 due to bookout transactions.

Load diversification fees are payments 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.

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

The table below summarizes deferred credits as of Sept. 30, 2004 and 2003.

Hedging and Derivative Instrument Activities

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

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures

Deferred Credits

As of Sept. 30 — thousands of dollars

	2004	2003
Customer reimbursable projects	**$ 183,933**	$ 153,190
Third AC intertie capacity agreements	**119,546**	122,612
Derivative/SFAS 133 mark-to-market	**106,513**	26,994
Load diversification fees	**81,163**	86,742
Fiber optic leasing fees	**59,335**	65,341
Enron settlement	**54,000**	94,000
Deferred CSRS	**6,600**	13,200
Unearned option premium revenue	**3,597**	12,822
Other miscellaneous long-term liabilities	**15**	113
Total	**$ 614,702**	$ 575,014

contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2004 or 2003.

Purchased and Written Options

In fiscal year 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.

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

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

The following table reflects the purchased and written options outstanding as of Sept. 30, 2004 and 2003.

Purchased and Written Options

As of Sept. 30

	2004	2003
Purchased options		
Outstanding	**196,800 MWh**	—
Average strike price	**$ 56.45**	—
Written options		
Outstanding	—	1,972,800 MWh
Average strike price	—	$ 40.33

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheets as of Sept. 30, 2004 and 2003. The carrying value reflected in the Balance Sheets approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Interest Rate Swap Transactions

In fiscal year 2003, BPA entered into two floating-to-fixed LIBOR interest rate swaps to help manage interest rate risk related to its long-term debt portfolio. In the first swap transaction, BPA pays a fixed 3.1 percent on $300 million notional amount for 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 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 special hedge accounting treatment under SFAS 133. The floating interest rates on the swaps are reset on a weekly basis. BPA recorded a $2.05 million fair value gain and a $7.9 million fair value loss in the Statements of Revenues and Expenses for fiscal years 2004 and 2003 respectively, related to the interest rate swap transactions.

Adoption of Statement 133 and Related Guidance

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

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

For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. BPA may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2004, 2003 and 2002, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

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

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

In April 2003, the FASB issued SFAS 149, which amends financial accounting and reporting for derivative instruments, including the accounting treatment for certain forward power sales and purchase contracts. SFAS 149 is effective for new contracts transacted after July 1, 2003. The normal purchase and sales exception previously allowed for bookout transactions under DIG issue C-15 was effectively eliminated by SFAS 149 and related guidance. As of Sept. 30, 2004, BPA recorded a $51 million fair value unrealized gain related to power purchase and sale transactions impacted by SFAS 149.

BPA recorded a SFAS 133 fair value unrealized gain in the Statement of Revenues and Expenses related to its derivative portfolio (including physical power purchase and sale transactions and purchased options) of $89.4 million, $55.3 million and $38.4 million for fiscal years 2004, 2003 and 2002 respectively.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $158 million, $190 million and $93 million at Sept. 30, 2004, 2003 and 2002 respectively. For revenue purposes, BPA operates as two segments: the Power Business Line and the Transmission Business Line. The table in Note 9 reflects the revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing agency, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS and the payment of certain irrigation costs as discussed in Note 7.

Fish Credits

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 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 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.

Prior to fiscal year 1995, over $325 million of credits had accrued since the Act passed in 1980. The Fish Cost Contingency Fund (FCCF) was established for credits earned by BPA but not applied prior to fiscal year 1995. The FCCF was only to be accessed under specified criteria. Since the establishment of the FCCF, BPA has applied for and taken an FCCF credit twice. The first time occurred in fiscal year 2001 when the Pacific Northwest experienced a severe drought. BPA accessed the fund again in fiscal year 2003 due to adverse hydro conditions and applied the remaining FCCF credits of $79 million, which depleted the fund.

BPA has taken 4(h)(10)(C) fish credits annually since fiscal year 1995.

Recent Accounting Pronouncements

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities – an interpretation of ARB No. 51." In December 2003, FIN 46 was reissued as FIN 46R, which contained revisions to address certain implementation issues. FIN 46 clarifies the application of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The interpretation differentiates between an entity with a majority voting interest (the previous requirement under ARB No. 51) and entities that have controlling financial interest through other arrangements that may not involve any voting interests and how these types of entities (variable interest entities) may need to be consolidated. For non-public entities there is no distinction in effective dates for Variable Interest Entities (VIEs) and non-VIEs. The application of FIN 46 is required for all entities created before Dec. 31, 2003, by no later than the beginning of the first interim or annual reporting period beginning after Dec. 15, 2003. For entities created after Dec. 31, 2003, application of FIN 46 is required as of the date they first become involved with the respective entities. Northwest Infrastructure Financing Corporation (NIFC) is the FCRPS's only VIE as of Sept. 30, 2004. NIFC has been consolidated into the BPA financial statements for fiscal year 2004. (See Note 4 for a discussion of NIFC.)

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 $212 million decrease to both operating revenues and purchased power expense for fiscal year 2004. 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.

FASB has issued an Exposure Draft on a Proposed Interpretation of SFAS Statement No. 143, "Accounting for Conditional Asset Retirement Obligations." SFAS 143 requires the recognition of a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The proposed interpretation is in response to diverse accounting practices that have developed with respect to the timing of liability recognition for conditional asset retirement obligations. If adopted, the interpretation may be applicable to BPA effective in fiscal year 2005.

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. 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 $68.6 million, $67.7 million and $67.4 million for fiscal years 2004, 2003 and 2002 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. As a result of the Energy Policy Act of 1992 BPA directly funds operation and maintenance expenses and capital efficiency and reliability improvements for Corps and Reclamation generating facilities.

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

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

The table shows the term repayments on the remaining federal appropriations as of Sept. 30, 2004.

Federal Appropriations

As of Sept. 30 — thousands of dollars

Term Repayments	
2005	$ 104,673
2006	68,939
2007	33,694
2008	10,913
2009	9,889
2010+	4,215,860
	$ 4,443,968

The weighted average interest rate was 7.0 percent on outstanding appropriations as of Sept. 30, 2004. Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

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, 2004, of the total $2.9 billion of outstanding bonds, $780 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, 2004, for similar maturities, exceeds carrying value by approximately $224 million, or 7.7 percent.

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

4. Nonfederal Projects

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

BPA recognizes expenses for these projects based upon total project cash funding requirements.

Operating expense for the projects of $230 million, $223 million and $175 million in fiscal years 2004, 2003 and 2002 respectively, is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $248 million, $120 million, and $230 million for fiscal years 2004, 2003 and 2002 respectively, is reflected as nonfederal projects expense in the accompanying Statements of

Bonds issued to U.S. Treasury

Long-Term Debt — thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Amount	Cumulative Total
January 2000	none	2005	7.15%	$ 53,500	$ 53,500
January 2001	none	2005	5.65%	20,000	73,500
January 2001	none	2005	5.65%	25,000	98,500
March 2002	none	2005	4.60%	110,000	208,500
March 2002	none	2005	4.60%	30,000	238,500
May 1997	none	2005	6.90%	80,000	318,500
June 2002	none	2005	3.75%	60,000	378,500
June 2002	none	2005	3.75%	40,000	418,500
September 2000	none	2005	6.70%	20,000	438,500
October 2002	none	2005	3.00%	50,000	488,500
November 2002	none	2005	2.80%	40,000	528,500
April 2003	none	2006	2.40%	40,000	568,500
April 2003	none	2006	2.40%	25,000	593,500
July 2003	none	2006	2.30%	75,000	668,500
July 2003	none	2006	2.30%	30,000	698,500
August 1996	none	2006	7.05%	70,000	768,500
September 2000	none	2006	6.75%	40,000	808,500
September 2002	none	2006	3.05%	100,000	908,500
September 2002	none	2006	3.05%	30,000	938,500
September 2002	none	2006	3.05%	20,000	958,500
September 2003	none	2006	2.50%	20,000	978,500
September 2003	none	2006	2.50%	25,000	1,003,500
December 2002	none	2006	3.05%	40,000	1,043,500
January 2004	none	2007	2.50%	60,000	1,103,500
January 2004	none	2007	2.50%	25,000	1,128,500
April 2003	none	2007	2.90%	40,000	1,168,500
April 2004	none	2007	2.95%	65,000	1,233,500
April 2004	none	2007	2.95%	35,000	1,268,500
July 2003	none	2007	2.95%	25,000	1,293,500
July 2004	none	2007	3.45%	50,000	1,343,500
July 2004	none	2007	3.45%	25,000	1,368,500
August 1997	none	2007	6.65%	111,300	1,479,800
September 2003	none	2007	3.10%	20,000	1,499,800
September 2004	none	2007	3.10%	30,000	1,529,800
September 2004	none	2007	3.10%	30,000	1,559,800
January 2004	none	2008	2.95%	65,000	1,624,800
January 2004	none	2008	2.95%	30,000	1,654,800
April 1998	none	2008	6.00%	75,300	1,730,100
April 1998	none	2008	6.00%	25,000	1,755,100
July 2004	none	2008	3.80%	25,000	1,780,100
August 1998	none	2008	5.75%	40,000	1,820,100
September 1998	none	2008	5.30%	104,300	1,924,400
May 1998	none	2009	6.00%	72,700	1,997,100
May 1998	none	2009	6.00%	37,700	2,034,800
July 1989	none	2009	8.55%	40,000	2,074,800
January 2001	none	2010	6.05%	60,000	2,134,800
January 2001	none	2010	6.05%	30,000	2,164,800
May 1998	none	2011	6.20%	40,000	2,204,800
June 2001	none	2011	5.95%	25,000	2,229,800
August 2001	none	2011	5.75%	50,000	2,279,800
January 1998	none	2013	6.10%	60,000	2,339,800
September 1998	none	2013	5.60%	52,800	2,392,600
February 1999	none	2014	5.90%	60,000	2,452,600
April 1998	2008	2028	6.65%	50,000	2,502,600
August 1998	none	2028	5.85%	106,500	2,609,100
August 1998	none	2028	5.85%	112,300	2,721,400
May 1998	2008	2032	6.70%	98,900	2,820,300
April 2003	2008	2033	5.55%	40,000	2,860,300
September 2004	none	2034	5.60%	40,000	2,900,300
				$ 2,900,300	$ 2,900,300
Less current portion					(438,500)
					$ 2,461,800

The weighted average interest rate was 4.9 percent on outstanding bonds issued to U.S. Treasury as of Sept. 30, 2004. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

Revenues and Expenses. Refinancing activities reduced debt service by $333 million, $463 million and $319 million for fiscal years 2004, 2003 and 2002 respectively, from rate case estimates.

The fair value of all Energy Northwest debt exceeds recorded value by $454 million, or 7.5 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2004. All other nonfederal projects' debt approximates fair value as stated.

Construction of the Schultz-Wautoma transmission line was financed through Northwest Infrastructure Financing Corporation (NIFC), a Delaware "Special Purpose Corporation," formed on Dec. 17, 2003. 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 managing construction 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 at a bargain purchase price. 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. Therefore the bonds are included as nonfederal debt on FCRPS's financial statements. NIFC's assets are included in FCRPS other assets at Sept. 30, 2004.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2004.

Nonfederal Projects Debt

As of Sept. 30 — thousands of dollars

	Principal Repayments
2005	$ 234,896
2006	253,632
2007	296,435
2008	304,593
2009	310,789
2010+	5,053,483
	$ 6,453,828

The weighted average interest rate was 5.6 percent on the major portion of outstanding nonfederal projects debt as of Sept. 30, 2004.

5. Investor-owned Utility Exchange Benefits

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), beginning in 1982 BPA entered into residential exchange contracts with most of its electric utility customers. These contracts 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.

IOU Exchange Benefit amounts for fiscal years 2005 and 2006 could range from $382 million to $750 million for the two years combined depending on the level of SN CRAC in fiscal year 2006. These estimates include $20 million assumed annual benefits to Portland General Electric from its 258-aMW power purchase. As the SN CRAC percentage has been set at zero percent for fiscal year 2005, an estimate for fiscal year 2005 IOU Exchange Benefits has been recorded as a current liability on the Balance Sheet.

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 on the Balance Sheets (for total floor of $500 million for this time period). 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 on the Balance Sheets.

Financial benefits beyond fiscal year 2011 cannot currently be quantified.

6. Accrued Plant Removal Costs

Pursuant to regulation, BPA collects in rates removal costs for certain assets that do not have associated legal asset retirement obligations. At Sept. 30, 2004 and 2003, BPA has estimated $105 million and $147 million regulatory liabilities respectively, for removal costs and has reclassified these amounts from accumulated depreciation to a regulatory liability.

7. Commitments and Contingencies

Purchase and Sales Commitments

BPA has entered into Subscription power sales for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. These contracts run for as short as three 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, 2004.

Purchase Power and Sales Commitments

As of Sept. 30 — thousands of dollars

	Purchase	Sales
2005	$ 629,994	$ 2,279,339
2006	571,990	2,117,166
2007	92,202	1,553,848
2008	48,561	1,563,224
2009	48,878	1,562,069
2010+	98,815	3,139,667
	$1,490,440	**$12,215,313**

Augmentation commitments run through 2006. Purchases and sales have not been reduced for bookouts.

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, $17 million, and $25 million for fiscal years 2004, 2001 and 1997 respectively. Future irrigation assistance payments ultimately could total $667 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The following table summarizes future irrigation assistance distributions as of Sept. 30, 2004.

Irrigation Assistance

As of Sept. 30 — thousands of dollars

	Distributions
2005	$ —
2006	—
2007	—
2008	2,950
2009	6,590
2010+	657,693
	$ 667,233

On Aug. 2, 2004, BPA received an updated schedule of Irrigation Assistance (through Sept. 30, 2003) from the Bureau of Reclamation. The numbers above, reflect that new schedule. They exclude $56.6 million assistance for Lower Teton, which was never completed, therefore never produced electricity and the administrator has no obligation to recover these costs.

Additional Pension and Other Post-Retirement Plan Contributions Retirement Benefits

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 $30.9 million, $35.1 million and $55.2 million to the U.S. Treasury during fiscal years 2004, 2003 and 2002, respectively. These amounts were recorded as expense when paid. At Sept. 30, 2004, FCRPS has scheduled additional payments totaling $119.6 million as shown in the following table.

Additional Pension and Other Post-Retirement Plan Contributions

As of Sept. 30 — thousands of dollars

	Scheduled Contributions
2005	$ 26,500
2006	23,200
2007	21,100
2008	18,000
2009*	30,750
	$ 119,550

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

* 2009 is an estimate 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.

Decommissioning and Restoration Costs

In 1999 Energy Northwest transferred remaining WNP-3 and WNP-5 assets, including the real property, and site restoration liability to a consortium of local governments named the Satsop Redevelopment Project. BPA's site restoration obligations related to WNP-3 and WNP-5 were satisfied/liquidated as part of that transfer.

In December 2003, the state of Washington's Energy Facility Site Evaluation Council (EFSEC) approved Resolution No. 302, approving Energy Northwest's revised Dec. 5, 2002 Site Restoration Plan for WNP-1 and WNP-4. This approval was part of a contemporaneous comprehensive agreement between Energy Northwest, EFSEC, BPA and the U.S. Department of Energy – Richland Operations Office (lessor of the real property upon which the partially completed WNP-1 and WNP-4 are located). Under the terms of the comprehensive agreement, the level of site restoration agreed to involves partial demolition and sealing of project structures (Level 3D – without removal of the turbine pedestals). BPA committed to fund that level of site restoration for both projects in two phases. The estimated total site restoration costs for both sites is $31 million (2003 dollars).

Phase 1 will involve completion of near term restoration (within 18 to 24 months of Dec. 15, 2003) involving essential "Health, Safety and Environmental" protection designed to place the sites in a safe state for potential reuse and/or long-term storage. Absent long-term reuse, Phase 2 will commence in 23 years and will complete all remaining activities to implement Level 3D restoration.

In order to fund the Phase 2 site restoration obligations, BPA has placed $18 million in an external Trust Fund. BPA believes those funds plus projected earnings over the 23-year horizon will be adequate to cover most if not all costs for Phase 2 activities. Phase 2 site restoration will take place absent long-term reuse of the site and structures. BPA's obligation is not, however, conditioned upon the posited earnings growth of the initial amounts deposited in the Trust Fund or upon the posited total cost estimate. A reasonable extension of time could be provided if such additional funds for completion of Phase 2 site restoration are ultimately required due to higher than estimated costs to complete the work.

Decommissioning costs for Columbia Generating Station (CGS) are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for CGS. The sinking fund is 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. Sinking 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 $91.9 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143) for CGS decommissioning costs. Payments to the sinking funds for fiscal years 2004, 2003 and 2002 were approximately $5 million, $4.8 million and $4.5 million respectively. The sinking fund balances at Sept. 30, 2004, are $85 million and $9.7 million for decommissioning and site restoration respectively.

In January 1993, the Portland General Electric (PGE) board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $265 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2004, Eugene Water and Electric Board's (EWEB) 30-percent share, which BPA backs, of this estimated remaining liability is $46 million (fair value basis, see Note 1, Asset Retirement Obligations, SFAS 143). The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements have been greater in the early years of decommissioning and will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for fiscal years 2001, 2002 and 2003. For fiscal years 1995 through 2001, funding for the Trojan decommissioning trust fund was being applied directly to the decommissioning expenses. In fiscal years 2002 and 2003, the decommissioning trust fund was used to fund a portion of the fiscal years 2002 and 2003 Trojan decommissioning expenses. In fiscal year 2004, BPA again directly funded Trojan decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover 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 impacts of SFAS 143.

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 $95.8 million limited to an annual maximum of $10 million. Assessments would be included in BPA's costs and recovered through current rates.

Endangered Species Act

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

Environmental Cleanup

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

8. Litigation

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

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

9. Segments

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

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

The FCRPS centrally manages all interest expense activity. Since 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. Inter-segment revenues are eliminated.

Major Customers

During fiscal years 2004, 2003 and 2002, no single customer represented 10 percent or more of the FCRPS' revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — thousands of dollars

	Power	Transmission	Corporate	Consolidating	FCRPS
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**	**94**	**(185,046)**	**—**
Total operating expenses	**2,257,111**	**518,438**	**(181,858)**	**(185,046)**	**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	120	(196,309)	—
Total operating expenses	2,725,220	497,378	(315,200)	(196,309)	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
2002					
Unaffiliated revenues	$ 2,967,074	$ 566,655	$ —	$ —	$ 3,533,729
Intersegment revenues	80,729	153,727	—	(234,456)	—
Total operating revenues	3,047,803	720,382	—	(234,456)	3,533,729
Unaffiliated expenses	2,605,847	283,809	(52,907)	—	2,836,749
Depreciation	174,164	161,041	—	—	335,205
Intersegment expenses	153,630	80,729	97	(234,456)	—
Total operating expenses	2,933,641	525,579	(52,810)	(234,456)	3,171,954
Net operating revenues	114,162	194,803	52,810	—	361,775
Interest expense	201,582	150,718	—	—	352,300
Net revenues (expenses)	$ (87,420)	$ 44,085	$ 52,810	$ —	$ 9,475

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2004 — thousands of dollars

Schedule A

		Commercial Power			Irrigation *(unaudited)*		
	Total Plant	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation
Bonneville Power Administration							
Transmission Facilities	$ 6,030,980	$ 5,539,134	$ 491,846	$ 6,030,980	$ —	$ —	$ —
Bureau of Reclamation							
Boise	144,493	27,577	404	27,981	(2,731)	67,539	64,808
Columbia Basin	1,964,353	1,238,515	60,682	1,299,197	495,526	142,008	637,534
Green Springs	35,726	11,175	212	11,387	9,934	8,070	18,004
Hungry Horse	149,212	121,985	285	122,270	—	—	—
Minidoka-Palisades	383,665	112,088	(37)	112,051	386	72,472	72,858
Yakima	264,243	6,127	725	6,852	13,762	127,826	141,588
Total Bureau Projects	2,941,692	1,517,467	62,271	1,579,738	516,877	417,915	934,792
Corps of Engineers							
Albeni Falls	50,605	43,126	2,809	45,935	—	—	—
Bonneville	1,401,586	927,603	69,656	997,259	—	—	—
Chief Joseph	629,987	571,149	18,368	589,517	—	163	163
Cougar	118,861	36,314	40,354	76,668	—	3,288	3,288
Detroit-Big Cliff	74,095	41,220	6,748	47,968	—	5,050	5,050
Dworshak	376,722	316,782	2,464	319,246	—	—	—
Green Peter-Foster	95,965	50,955	4,680	55,635	—	6,222	6,222
Hills Creek	51,457	18,463	1,265	19,728	—	4,623	4,623
Ice Harbor	223,909	159,247	3,937	163,184	—	—	—
John Day	657,206	494,244	14,816	509,060	—	—	—
Libby	577,223	433,212	1,240	434,452	—	—	—
Little Goose	255,468	212,068	1,738	213,806	—	—	—
Lookout Point-Dexter	113,180	50,192	10,787	60,979	—	1,496	1,496
William Jess (Lost Creek)	149,836	26,972	174	27,146	—	2,184	2,184
Lower Granite	414,613	332,599	8,459	341,058	—	—	—
Lower Monumental	276,546	230,564	3,071	233,635	—	—	—
McNary	397,747	300,736	21,626	322,362	—	—	—
The Dalles	424,917	308,486	66,985	375,471	—	—	—
Lower Snake	262,143	256,193	3,380	259,573	—	—	—
Columbia River Fish Bypass	920,589	376,958	529,058	906,016	—	—	—
Total Corps Projects	7,472,655	5,187,083	811,615	5,998,698	—	23,026	23,026
AFUDC on Direct Funded Projects	36,062	—	36,062	36,062	—	—	—
Irrigation Assistance at 12 Projects having no power generation	193,925	—	—	—	148,553	45,372	193,925
Total Plant Investment	16,675,314	12,243,684	1,401,794	13,645,478	665,430	486,313	1,151,743
Repayment obligation retained by Columbia Basin project	4,639	2,836 (1)	—	2,836	1,803	—	1,803
Investment in Teton project (2)	79,107	—	7,269 (2)	7,269	56,573	3,681	60,254
	$16,759,060	$12,246,520	$1,409,063	$13,655,583	$723,806	$489,994	$1,213,800

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

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

Non-reimbursable *(unaudited)*

	Navigation	Control	Flood Wildlife	Fish and Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	51,704	17.47%
Columbia Basin	—	17,489	6,054	3,071	1,008	91.36%
Green Springs	—	—	—	—	6,335	59.68%
Hungry Horse	—	26,942	—	—	—	81.94%
Minidoka-Palisades	—	64,404	2,718	10,651	120,983	29.31%
Yakima	—	2,547	50,397	296	62,563	7.80%
Total Bureau Projects	—	111,382	59,169	14,018	242,593	71.27%
Corps of Engineers						
Albeni Falls	183	274	—	4,213	—	90.77%
Bonneville	400,999	—	—	1,266	2,062	71.15%
Chief Joseph	—	—	4,977	6,330	29,000	93.58%
Cougar	548	38,357	—	—	—	64.50%
Detroit-Big Cliff	220	20,857	—	—	—	64.74%
Dworshak	9,733	31,934	—	15,809	—	84.74%
Green Peter-Foster	366	30,379	—	1,693	1,670	57.97%
Hills Creek	630	26,476	—	—	—	38.34%
Ice Harbor	57,184	—	—	3,541	—	72.88%
John Day	91,535	18,240	—	11,962	26,409	77.46%
Libby	—	95,308	876	15,950	30,637	75.27%
Little Goose	34,917	—	—	4,141	2,604	83.69%
Lookout Point-Dexter	748	49,355	—	602	—	53.88%
Lost Creek	—	52,967	24,483	29,435	13,621	18.12%
Lower Granite	52,605	—	—	13,108	7,842	82.26%
Lower Monumental	39,596	—	—	2,898	417	84.48%
McNary	70,413	—	—	4,972	—	81.05%
The Dalles	47,346	—	—	2,078	22	88.36%
Lower Snake	2,570	—	—	—	—	99.02%
Columbia River Fish Bypass	11,792	2,781	—	—	—	98.42%
Total Corps Projects	821,385	366,928	30,336	117,998	114,284	80.28%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	76.60%
Total Plant Investment	821,385	478,310	89,505	132,016	356,877	85.82%
Repayment obligation retained by Columbia Basin project	—	—	—	—	—	100.00%
Investment in Teton project	—	9,151	—	2,433	—	80.70%
	$ 821,385	$ 487,461	$ 89,505	$134,449	$356,877	85.80%

Federal Columbia River Power System

Consolidated Balance Sheets (Unaudited)

(Thousands of Dollars)

Assets

	March 31 2005	2004
Utility Plant		
Completed plant	**$ 12,459,535**	$ 12,058,593
Accumulated depreciation	**(4,485,325)**	(4,408,844)
	7,974,210	7,649,749
Construction work in progress	**1,318,057**	1,410,943
Net utility plant	**9,292,267**	9,060,692
Nonfederal Projects		
Conservation	**40,437**	43,761
Hydro	**146,210**	146,210
Nuclear	**2,220,775**	2,181,772
Terminated hydro facilities	**27,305**	28,090
Terminated nuclear facilities	**3,900,137**	3,889,847
Total nonfederal projects	**6,334,864**	6,289,680
Decommissioning Cost	**166,738**	123,935
IOU exchange benefits	**971,539**	–
Conservation, net of accumulated amortization	**318,330**	357,365
Fish & Wildlife, net of accumulated amortization	**114,263**	124,681
Current Assets		
Cash	**908,375**	969,776
Accounts receivable, net of allowance	**105,391**	108,395
Accrued unbilled revenues	**222,508**	209,167
Materials and supplies, at average cost	**79,931**	83,678
Prepaid expenses	**145,171**	118,666
IOU exchange benefits	**190,860**	–
Total current assets	**1,652,236**	1,489,682
Other Assets	**402,245**	275,274
	$ 19,252,482	$ 17,721,309

Capitalization and Liabilities

	March 31 2005	2004
Capitalization and Long-Term Liabilities		
Accumulated Net Revenues	**$ 1,084,976**	$ 691,250
Federal Appropriations	**4,347,309**	4,607,706
Capitalization Adjustment	**2,023,679**	2,090,903
Bonds issued to U.S. Treasury	**2,486,800**	2,481,385
Nonfederal Projects Debt	**6,215,757**	6,024,866
Decommissioning Reserve	**166,738**	123,935
IOU exchange benefits	**991,828**	41,751
Accrued plant removal costs	**110,658**	99,461
Total capitalization and long-term liabilities	**17,427,745**	16,161,257
Current Liabilities		
Current portion of federal appropriations	**104,673**	–
Current portion of bonds issued to U.S. Treasury	**290,000**	384,700
Current portion of nonfederal projects debt	**238,692**	264,814
Current portion of IOU exchange benefits	**190,860**	–
Accounts payable and other current liabilities	**406,643**	375,432
Total current liabilities	**1,230,868**	1,024,946
Deferred Credits	**593,869**	535,106
	$ 19,252,482	$ 17,721,309

QUARTERLY REPORT FOR THE SIX MONTHS ENDED MARCH 31, 2005

Federal Columbia River Power System

Consolidated Statements of Revenues and Expenses (Unaudited)

(Thousands of Dollars)

	Six months ended March 31		Twelve months ended March 31	
	2005	2004	**2005**	2004
Operating Revenues				
Revenues	**$ 1,514,786**	$ 1,514,616	**$ 2,973,666**	$ 3,130,086
SFAS 133 mark-to-market gain	**6,214**	28,413	**67,253**	62,448
Other revenues	**28,010**	27,598	**58,375**	60,487
U.S. Treasury credits for fish	**39,787**	36,504	**80,283**	145,124
Total operating revenues	**1,588,797**	1,607,131	**3,179,577**	3,398,145
Operating Expenses				
Operations and maintenance	**588,651**	511,472	**1,288,981**	1,142,503
Purchased power	**278,934**	291,557	**569,506**	750,306
Non-Federal projects	**158,723**	128,024	**279,174**	134,565
Federal projects depreciation	**182,773**	178,855	**370,157**	355,159
Total operating expenses	**1,209,081**	1,109,908	**2,507,818**	2,382,533
Net operating revenues	**379,716**	497,223	**671,759**	1,015,612
Interest Expense				
Interest on federal investment				
Appropriated funds	**55,772**	103,293	**165,520**	206,674
Bonds issued to U.S. Treasury	**98,168**	62,342	**146,077**	150,380
Allowance for funds used during construction	**(11,752)**	(15,890)	**(34,303)**	(34,574)
Net interest expense	**142,188**	149,745	**277,294**	322,480
Net Revenues	**$ 237,528**	$ 347,478	**$ 394,465**	$ 693,132

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, 2004, and the related statements of operations and 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, Gray's 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 of 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, 2004, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis ("MD&A") is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. The information in MD&A has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we express no opinion on it.

PricewaterhouseCoopers LLP

September 3, 2004

Management's Discussion and Analysis

Energy Northwest is a municipal corporation and joint operating agency of the State of Washington. Each 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, 2004, with the basic financial statements for the Fiscal Year ended June 30, 2003. Energy Northwest has adopted accounting policies and principles in accordance with accounting principles generally accepted in the United States of America. Energy Northwest applies Generally Accepted Accounting Principles (GAAP) to the extent it does not conflict with Governmental Accounting Standards Board (GASB) standards. (See Note B to financial statements)

Financial statements include balance sheets; statements of operations and fund equity; statements of cash flows; schedules of outstanding long-term debt and debt service requirements; and notes to financial statements for each Business Unit. Balance sheets present the financial position of each Business Unit based on an accrual basis. 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.

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 reflect cash receipts and disbursements and net changes resulting from operating, financing, and investment activities. The statements provide insight into what generates cash, where cash comes from, and what it was used for.

Notes to the 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.

Certain refinancings entered into during prior years have resulted in fixed-rate debt being defeased by variable-rate debt. This has exposed a portion of the outstanding debt to movements in interest rates. The objective in managing this interest rate exposure is to limit the impact of interest rate changes on earnings and cash flows, and to reduce overall borrowing costs. Maintenance of a mix of medium and long-term fixed-rate debt will manage these objectives.

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 produced 9,520 GWh of electricity in Fiscal Year 2004, as compared to 7,738 GWh of electricity in Fiscal Year 2003, which included economic dispatch of 16 GWh and 121 GWh, respectively. This increase in generation is a result of the station running the entire year after the completion of its 2-year refueling and maintenance outage at the end of Fiscal Year 2003.

Balance Sheet Analysis

Columbia Generating Station (CGS) has just completed more than a year of continuous generation, setting a station record for operating a total of 393 days for the period of July 3, 2003, to July 30, 2004.

Construction Work in Progress increased by $16,514,000, from $13,987,000 in Fiscal Year 2003 to $30,501,000 in Fiscal Year 2004. This increase is due mainly to three major projects: 1) Mandated Security Project: The Nuclear Regulatory Commission (NRC), after the September 11, 2001, terrorist attacks, mandated heightened security improvements to all nuclear facilities. These improvements must be completed by October 2004, and are currently on schedule. As of the end of Fiscal Year 2004, Energy Northwest had spent $5,590,000 on mandated security improvements. An additional $6,171,000 is to be spent in Fiscal Year 2005 for a total project cost of approximately $11,761,000. 2) Hydrogen Water Chemistry Injection Project: This project is in the final phases of construction and testing. The Hydrogen Water Chemistry Injection Project is being implemented by Energy Northwest to mitigate Intergranular Stress Corrosion Cracking (IGSCC). An established method for preventing the formation of cracks and reducing the growth rates of existing cracks, due to IGSCC, involves the reduction of oxygen and other oxidizing species in the reactor coolant; this reduction will be accomplished by injecting hydrogen into the feedwater system. The supply of hydrogen must come from a reliable on-site liquid hydrogen storage facility capable of meeting all design conditions while maintaining plant safety. The Hydrogen Water Chemistry Injection Project is to be placed in service during the second quarter of Fiscal Year 2005. Project costs through the end of Fiscal Year 2004 were $10,472,000. For Fiscal Year 2005, the project cost is budgeted at $288,000, for a total project cost of approximately $10,760,000. 3) Upgraded Security System Computer: The installation and testing of the Station Upgraded Security System Computer is to be completed during the second quarter of Fiscal Year 2005. This new computer replaces the current computer, which runs all of the security systems inside the protected area of CGS. Project costs as of the end of Fiscal Year 2004 were $4,022,000. For Fiscal Year 2005, the project cost is budgeted at $891,000 for a total project cost of approximately $4,913,000.

Nuclear fuel, net of accumulated amortization decreased by $19,226,000 from $121,275,000 in Fiscal Year 2003 to $102,049,000 in Fiscal Year 2004. During Fiscal Year 2004, CGS purchased $14,154,000 of nuclear fuel, which was offset by current year amortization of $33,380,000.

The Restricted Assets Special Funds increased $19,906,000, from $31,551,000 in Fiscal Year 2003 to $51,457,000 in Fiscal Year 2004, which is a result of financing additional construction projects that were not completed during Fiscal Year 2004, as part of the 2004 Bond Issue. The Debt Service Funds decreased $43,001,000 from $62,777,000 in Fiscal Year 2003 to $19,776,000 in Fiscal Year 2004 due to Bond Fund Reserve free-ups through the Debt Optimization Program. The Debt Optimization Program is designed to take advantage of current lower interest rates to refinance higher interest debt, if the debt is available to be "called" prior to maturity, as well as assisting Bonneville Power Administration (BPA) to free up current cash flows by refinancing current maturing debt with lower interest debt, which will mature in future years.

Long-Term Receivables decreased $3,523,000 from $6,591,000 in Fiscal Year 2003 to $3,068,000 in Fiscal Year 2004 primarily due to a $3,300,000 reclassification to Current Receivables related to a Fiscal Year 1992 Settlement Agreement with a third party. Current Assets increased $16,939,000 from $89,746,000 in Fiscal Year 2003 to $106,685,000 in Fiscal Year 2004, due to the following: 1) Cash and available-for-sale securities increased $2,646,000 in Fiscal Year 2004, due to a larger prepayment of Net Billing for Fiscal Year 2005, as compared to Fiscal Year 2004. 2) Reclassification of Long-Term Receivables to Current Receivables as mentioned above. 3) Interfund transfers that are eliminated in Combination of the Financial Statements.

Costs in Excess of Billings have increased $168,497,000 from $325,818,000 in Fiscal Year 2003 to $494,315,000 in Fiscal Year 2004. This is largely due to the Debt Optimization Program mentioned above. The lack of a need for funds to pay off current maturities results in costs that exceed billings. 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 $51,588,000 from $2,002,796,000 in Fiscal Year 2003 to $2,054,384,000 in Fiscal Year 2004, which was a result of the Fiscal Year 2004 Bond Issue. As explained above, in Fiscal Year 2004, new debt was issued for various CGS construction projects, as well as to support 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 expenses for each period on net-billed projects. No net revenues or losses are recognized and no equity is accumulated. The following changes from Fiscal Year 2003 to Fiscal Year 2004 for Net Operating Revenues are: Operating Revenues needed to cover expenditures are down $2,532,000 from $439,947,000 in Fiscal Year 2003 to $437,415,000 in Fiscal Year 2004. Nuclear fuel expenditures have increased $8,261,000, from $27,061,000 in Fiscal Year 2003 to $35,322,000 in Fiscal Year 2004, because of increased generation in a non-outage year. The increased generation during Fiscal Year 2004 resulted in higher Generation Taxes of $3,199,000 in Fiscal Year 2004, compared with $2,237,000 in Fiscal Year 2003. Also, Spent Fuel Disposal fees increased $1,776,000 from $7,253,000 in Fiscal Year 2003 to $9,029,000 in Fiscal Year 2004, due to the increased generation.

Operations and Maintenance expenditures were lower by a net $29,740,000 from $159,312,000 in Fiscal Year 2003 to $129,572,000 in Fiscal Year 2004. The refueling and maintenance outage in Fiscal Year 2003 accounted for $43,540,000 in costs not expended in Fiscal Year 2004. The offsetting increase of $13,800,000 was due to several factors including the Independent Spent Fuel Storage Installation operating throughout Fiscal Year 2004, including the loading and transferring of spent fuel casks to the new onsite storage facility. In addition, as mentioned above, the NRC has mandated security improvements, which included a significant increase in the CGS Security staff. Furthermore, Operations and Maintenance expenditures were further impacted in Fiscal Year 2004, each time the Homeland Security Threat Level increased. Operations and Maintenance staff were also faced with several challenges during Fiscal Year 2004, including steam leaks that were safely repaired without shutting down CGS, which when faced with the same situation in the past, the Operations and Maintenance staff would have shut the plant down.

Administrative and General Expenses were lower by $5,292,000, from $26,901,000 in Fiscal Year 2003 to $21,609,000 in Fiscal Year 2004, mainly due to the following items: In Fiscal Year 2003, incentive payments were a direct cost for CGS; in Fiscal Year 2004, the incentive payments were a cost to overhead, which resulted in a decrease of $4,735,000. Benefit costs were $1,242,000 less in Fiscal Year

2004, as compared to Fiscal Year 2003, due to less overtime and temporary labor in a non-outage year. Regulatory costs increased in Fiscal Year 2004, as compared to Fiscal Year 2003, by $1,597,000, because of fee increases from the Nuclear Regulatory Commission and Electric Power Research Institute. Decommissioning expenses increased $16,488,000 from $26,505,000 in Fiscal Year 2003 to $42,993,000 in Fiscal Year 2004, primarily due to a change in rate on the model for the accretion expense which was accounted for in Fiscal Year 2004. In Fiscal Year 2003, the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Obligations Associated with the Retirement of Long-Lived Assets* (SFAS 143) resulted in an initial increase in expense, which was accounted for as an increase to Cost in Excess of Billings in compliance with the Net-Billing Agreement with BPA instead of a Cumulative Effect of Accounting Change. SFAS 143 calls for the Asset Retirement Obligation to be recorded at a rate depreciated over the life of the plant. The amount is a combination of probable cases for accomplishing the required retirement obligations and their associated probabilities. The amount will also be increased each year to account for the accretion value of the obligation. An increase in Fiscal Year 2004 was recorded to bring us to the value required per calculation as adopted by SFAS 143 and will follow the same impact as mentioned above. (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 adversely affected by continuing low rates of return and lower cash balances resulting in a decline of $4,873,000 from $6,751,000 in Fiscal Year 2003 to $1,878,000 in Fiscal Year 2004. Additionally, interest expense increased by $1,244,000 from $113,002,000 in Fiscal Year 2003 to $114,246,000 in Fiscal Year 2004, due mainly to $41,330,000 of new debt issued in Fiscal Year 2003 at a 5-5.25 percent interest rate, offset by the reduced interest expense benefit of the Debt Optimization Plan. Amortization of Bond Discount Expense and Amortization of Bond Refunding netted a decrease in expense of $1,305,000 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 1,800 ft. below the dam located south of Packwood, Washington. Packwood produced 90.06 GWh of electricity in Fiscal Year 2004 versus 91.08 GWh in Fiscal Year 2003.

Balance Sheet Analysis

Current Assets have increased $57,000 from $2,222,000 in Fiscal Year 2003 to $2,279,000 in Fiscal Year 2004, due to increased sales revenue. As a result, Packwood accrued $412,000 in excess funding that was available to be returned to the Participants in October 2004.

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 increased because of the cost increases detailed below. Operations and Maintenance, along with Administrative and General expenditures increased $353,000, from $1,086,000 in Fiscal Year 2003 to $1,439,000 in Fiscal Year 2004. This was due to the beginning of relicensing efforts, which totaled $322,000 for Fiscal Year 2004. The Federal Energy Regulatory Commission (FERC) issued a 50-year operating license to Packwood on March 1, 1960. The current license will expire on February 28, 2010.

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 Fiscal Year 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 $5,096,000 from $1,956,201,000 in Fiscal Year 2003 to $1,961,297,000 in Fiscal Year 2004, due to debt restructuring to take advantage of lower interest rates.

Statement Of Operations Analysis

Investment Income decreased $1,305,000, from $2,566,000 in Fiscal Year 2003 to $1,261,000 in Fiscal Year 2004, due to historically low rates of return.

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 $28,131,000 from $1,761,562,000 in Fiscal Year 2003 to $1,789,693,000 in Fiscal Year 2004, due to principal payments and debt restructuring to take advantage of lower interest rates.

Statement Of Operations Analysis

Investment Income decreased $2,719,000, from $3,636,000 in Fiscal Year 2003 to $917,000 in Fiscal Year 2004, due to historically low rates of return.

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 Fiscal Year 2004 totaled $14,719,000 as compared to Fiscal Year 2003 revenues of $11,163,000, an increase of $3,556,000. 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, the DOE would be billed for 50 percent of the restoration and cleanup efforts. The project was completed in Fiscal Year 2004, with Energy Northwest recognizing revenue of $3,792,000, an increase of $3,431,000 over Fiscal Year 2003. Other major business program contributors to revenue growth were: operations and maintenance services by $349,000 and environmental services by $322,000.

Total operating revenues increased 32 percent in Fiscal Year 2004, however net revenues for the Fiscal Year 2004 showed a $987,000 loss as compared to approximately a $683,000 loss in Fiscal Year 2003.

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. Two of Energy Northwest's Research and Investigation business projects, BioEnergy Solutions and Wind Mining, accounted for $1,000,000 in expenditures with no revenues. BioEnergy Solutions is a business line of Energy Northwest working with Soil Search, LLC, of Kennewick, Washington, that has developed a full-scale biomass power test unit at a dairy farm near Pasco, Washington. This unit is testing a newly developed bioreactor technology produced by Soil Search. This research and development effort may provide a quantum leap in methane production from dairy cow manure. In Fiscal Year 2004, approximately $591,000 was expended on developing this project. Wind Mining efforts continued in Fiscal Year 2004, with approximately $409,000 being expended. These efforts are to explore, site, and demonstrate wind resources for potential new wind sites.

In Fiscal Year 2004, $370,000 was spent on sales and marketing efforts and an additional $1,305,000 was spent on developing the organizational infrastructure to support the growing business.

The BDF receives contributions from the Internal Service Fund to cover cash needs during this startup period. Initial start-up costs are not expected to be paid back and are shown as contributions.

Grays Harbor Energy Facility

Becoming the operator of the Grays Harbor Energy Facility was a component in Energy Northwest's strategic plan to eventually own and operate combined cycle gas turbine power plants. This contract was intended to be our first step toward establishing a credible position in the Combustion Turbine power generation market. It was to provide the basis for Energy Northwest to become a major supplier of Operations & Maintenance services to other public utilities in the Northwest and to become an owner of gas turbine generating facilities, as well.

On January 15, 2001, Energy Northwest entered into an agreement to sell the Grays Harbor Energy Facility site to the Duke Energy North America (DENA) affiliate, Duke Energy Grays Harbor, LLC (DEGH). The actual sale of the land and assets at the site in Grays Harbor County near Elma, Washington, has already been successfully concluded. This sale was to lead to the construction by DEGH of a 630 megawatt combined cycle 2-on-1 gas turbine power plant at the site to be on-line by late 2003. Energy Northwest was to become the operator of the Grays Harbor Energy Facility. In September 2002, due to market conditions, DENA placed the project in "Construction Suspension." In February 2004, DENA announced it has no intention of completing the facility with its own funds. Energy Northwest and DENA have a contract for site preservation services during this construction suspension time period. Per the agreement with DENA, if construction is 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 $5,000,000 and dissolution of the O&M contract. DENA has expressed interest regarding the sale of the site for completion by "public power." Energy Northwest will perform due dilligence in exploring this opportunity. Revenues for Fiscal Year 2004 were recorded for reimbursable costs and services provided to DENA.

Statement Of Operations Analysis

Non-Operating revenues were $1,479,000 and $407,000 for Fiscal Year 2003 and Fiscal Year 2004, respectively.

Nine Canyon Wind Project

The Nine Canyon Wind Project is owned and operated by Energy Northwest. The Project is located in the Horse Heaven Hills area southeast 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 with Energy Northwest. 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 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 63.74 megawatts, which produces enough energy capacity for approximately 26,000 average homes.

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

Long-term debt in the form of bonds were sold in the amount of $70,675,000 to finance Phase I and $21,720,000 for Phase II of the Project. Construction for both phases has been completed and declared commercially operational. Principal payments began Fiscal Year 2004 in the amount of $2,060,000. Thus, a reduction in Long-term debt, Revenue bonds payable from Fiscal Year 2003 of $92,395,000 to $90,335,000 in Fiscal Year 2004.

Statement of Operations Analysis

Operating Revenues increased $1,849,000 from $3,464,000 in Fiscal Year 2003 to $5,313,000 in Fiscal Year 2004. The project received revenue from the billing of the project purchasers at an average rate of $34.98 per MWh for Fiscal Year 2004. Other contribution of funds includes $1,537,000 from the Renewable Energy Production Incentive (REPI). 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 received 77 percent of the applied REPI funding. 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 increases in the billing of the project participants in order to cover total project costs.

The agreement with project purchasers anticipates a loss in Fiscal Year 2005 with additional cash needs being paid from existing project reserve funds. The reserve funds were established so participant payments would increase at a rate of 3 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 ISF provides services to the other funds. This accounts for the central procurement of certain common goods and services for the business units on a cost reimbursement basis. (See Notes A and B to financial statements).

Balance Sheet Analysis

The Balance Sheet decreased $4,242,000, from $51,602,000 in Fiscal Year 2003 to $47,360,000 in Fiscal Year 2004. The decrease in Assets is comprised of a net decrease in Utility Plant of $967,000 due to current year depreciation, as well as a decrease of $2,643,000 in Interfund Transfers that are due to the Internal Service Fund, which are eliminated in the Combining of the Financial Statements. The decrease of $4,242,000 in Fund Equity and Liabilities is comprised of a $12,551,000 reduction in Accounts Payable; however, this is offset by a $5,960,000 increase in Interfund Transfers due to other Funds eliminated in the Combining of the Financial Statements, as well as a $2,860,000 increase in Fund Equity. The increase in Fund Equity resulted from a transfer to the Business Development Fund of $2,791,000 of deferred Fiscal Year 2003 Incentive Fee.

Statement Of Operations Analysis

Net Revenues for Fiscal Year 2004 were $69,000 versus $434,000 for Fiscal Year 2003. The main contributor to this variance of $365,000 is the suspension of the Performance Fee award program by BPA.

BALANCE SHEETS

As of June 30, 2004 (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	2004 COMBINED TOTAL
ASSETS										
UTILITY PLANT (NOTE B)										
In service	$ 3,482,467	$ 12,991	$ -	$ -	$ 882	$ -	$ 68,485	$ 3,564,825	$ 44,352	$ $3,609,177
Not in service			25,253					25,253		25,253
Accumulated depreciation	(1,953,510)	(12,417)	(25,253)		(246)		(4,615)	(1,996,041)	(30,606)	(2,026,647)
	1,528,957	574	-	-	636	-	63,870	1,594,037	13,746	1,607,783
Nuclear fuel, net of accumulated amortization	102,049							102,049		102,049
Construction work in progress	30,501							30,501		30,501
	1,661,507	574	-	-	636	-	63,870	1,726,587	13,746	1,740,333
RESTRICTED ASSETS (NOTE B)										
Special funds										
Cash	16,201	1	5,934	3,344			2	25,482	1,942	27,424
Available-for-sale investments	35,256	282	7,668	7,917			3,404	54,527	1,010	55,537
Accounts and other receivables							1,554	1,554		1,554
Debt service funds										
Cash	19,776	1	24,244	16,528			4,521	65,070		65,070
Available-for-sale investments		744	21,286	9,998			6,028	38,056		38,056
Due from other funds	1,874							1,874		
Other receivables			12					12		12
	73,107	1,028	59,144	37,787	-	-	15,509	186,575	2,952	187,653
LONG-TERM RECEIVABLES (NOTE B)	3,068							3,068		3,068
CURRENT ASSETS										
Cash	735		283	63	1	31		1,113	1,556	2,669
Available-for-sale investments	5,483	1,762	25,222	11,441	3,551	1,135	2,011	50,605	22,620	73,225
Accounts & other receivables	4,461	454	4,179		2,067	82		11,243	73	11,316
Due from Participants	21		9	8				38		38
Due from other business units	7,393		341			113	409	8,256	6,170	
Due from other funds	16,684	5	10,612	8,173			158	35,632		
Materials and supplies	71,481						225	71,706		71,706
Prepayments and other	427	58			95			580	243	823
Nuclear fuel held for sale			1,095					1,095		1,095
Plant & equipment held for sale			1,166					1,166		1,166
	106,685	2,279	42,907	19,685	5,714	1,361	2,803	181,434	30,662	162,038
DEFERRED CHARGES										
Costs in excess of billings	494,315	1,856	1,944,067	1,758,787				4,199,025		4,199,025
Unamortized debt expense	16,509	2	15,657	12,524			3,981	48,673		48,673
Other deferred charges	1						4,843	4,844		4,844
	510,825	1,858	1,959,724	1,771,311	-	-	8,824	4,252,542		4,252,542
TOTAL ASSETS	$ 2,355,192	$ 5,739	$ 2,061,775	$ 1,828,783	$ 6,350	$ 1,361	$ 91,006	$ 6,350,206	$ 47,360	$ 6,345,634

* Project recorded on a liquidation basis
See notes to financial statements

BALANCE SHEETS *(Continued)*

As of June 30, 2004 (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	2004 COMBINED TOTAL
FUND EQUITY & LIABILITIES										
FUND EQUITY	$ -	$ -	$ -	$ -	$ 564	$ 1,356	$ (5,523)	$ (3,603)	$ 6,981	$ 3,378
LONG-TERM DEBT (NOTE E)										
Revenue bonds payable	2,041,030	3,358	1,977,325	1,934,790			90,335	6,046,838		6,046,838
Unamortized discount on bonds - net	62,864	(6)	49,876	(115,758)			671	(2,353)		(2,353)
Unamortized gain/(loss) on bond refundings	(49,510)	29	(65,904)	(29,339)				(144,724)		(144,724)
	2,054,384	3,381	1,961,297	1,789,693	-	-	91,006	5,899,761		5,899,761
LIABILITIES-PAYABLE FROM RESTRICTED ASSETS (NOTE B)										
Special funds										
Accounts payable and accrued expenses	91,332		26,173				491	117,996	2,407	120,403
Due to other funds	18,558	2	10,526	8,158			158	37,402		
Other deferred credits			1,275		185			1,460		1,460
Debt service funds										
Accrued interest payable	21,651	46	45,456	26,511			2,460	96,124		96,124
Due to other funds		3	86	15				104		
	131,541	51	83,516	34,684	185	-	3,109	253,086	2,407	217,987
OTHER NONCURRENT LIABILITIES	25,216							25,216		25,216
CURRENT LIABILITIES										
Cash overdrafts		29						29		29
Current maturities of long-term debt	119,025	393					2,060	121,478		121,478
Accounts payable and accrued expenses	18,231	62	11,553	198	664	5	189	30,902	28,763	59,665
Due to Participants	6,712	1,141	5,409	3,822				17,084		17,084
Due to other business units	83	682		386	4,937		165	6,253	8,173	
	144,051	2,307	16,962	4,406	5,601	5	2,414	175,746	36,936	198,256
DEFERRED CREDITS										
Advances from Members & others									1	1
Other deferred credits									1,035	1,035
	-	-	-	-	-		-		1,036	1,036
TOTAL LIABILITIES	2,355,192	5,739	2,061,775	1,828,783	5,786	5	96,529	6,353,809	39,973	6,341,850
TOTAL FUND EQUITY AND LIABILITIES	$ 2,355,192	$ 5,739	$ 2,061,775	$ 1,828,783	$ 6,350	$ 1,361	$ 91,006	$ 6,350,206	$ 47,360	$ 6,345,634

* Project recorded on a liquidation basis

See notes to financial statements

STATEMENTS OF OPERATIONS AND FUND EQUITY

For the year ended June 30, 2004 (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	2004 COMBINED TOTAL
OPERATING REVENUES	$ 437,415	$ 1,915	$ -	$ -	$ 14,719	$ -	$ 5,313	$ 459,362	$ 76,500	$ 459,431
OPERATING EXPENSES										
Services to other business units									75,029	
Nuclear fuel	35,322							35,322		35,322
Spent fuel disposal fee	9,029							9,029		9,029
Decommissioning	42,993						24	43,017		43,017
Depreciation and amortization	79,932	333			127		3,252	83,644	1,482	83,644
Operations and maintenance	129,572	1,250					2,037	132,859		132,859
Administrative & general	21,609	189					20	21,818		21,818
Generation tax	3,199	19					30	3,248		3,248
New business initiatives					15,649			15,649		15,649
Total operating expenses	321,656	1,791	-	-	15,776	-	5,363	344,586	76,511	344,586
NET OPERATING REVENUES (EXPENSES)	115,759	124			(1,057)		(50)	114,776	(11)	114,845
OTHER INCOME & EXPENSE										
Non-operating revenues			113,861	88,732		407		203,000		203,000
Investment income	1,878	26	1,261	917	19	15	120	4,236	80	4,236
Gain/(loss) on current bond redemption		4						4		4
Interest expense and discount amortization	(119,604)	(154)	(102,947)	(86,801)			(4,706)	(314,212)		(314,212
Plant preservation & termination costs			(12,953)	(2,848)				(15,801)		(15,801
Depreciation and amortization			(5)			(2)		(7)		(7
Revaluation of Site Restoration			582					582		582
Other	1,967		201		51	(339)		1,880	0	1,880
NET REVENUES (EXPENSES)	-	-	-	-	(987)	81	(4,636)	(5,542)	69	(5,473
Distribution & Contributions	-	-	-	-	(1,225)	(573)	1,374	(424)	2,791	2,367
Beginning Fund Equity	-	-	-	-	2,776	1,848	(2,261)	2,363	4,121	6,484
ENDING FUND EQUITY	$ -	$ -	$ -	$ -	$ 564	$ 1,356	$ (5,523)	$ (3,603)	$ 6,981	$ 3,378

* Project recorded on a liquidation basis
See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 2004 (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	2004 COMBINED TOTAL
CASH FLOWS FROM OPERATING & OTHER ACTIVITIES									
Operating revenue receipts	$ 271,792	$ 2,488	$ -	$ -	$ 5,624	$ -	$ 5,264	$ -	$ $285,168
Cash payments for operating expenses	(191,353)	(1,833)					(2,422)		(195,608)
Non-operating revenue receipts			95,457	36,234		887			132,578
Cash payments for preservation, termination expense			(11,223)	(2,909)					(14,132)
Cash payments for services						(1,950)		(516)	(2,466)
Cash payments for new business					(2,924)				(2,924)
Receipts for grants/contributions							232		232
Net cash provided (used) by operating and other activities	80,439	655	84,234	33,325	2,700	(1,063)	3,074	(516)	202,848
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES									
Proceeds from bond refundings	491,458		68,037	90,583					650,078
Refunded bond escrow requirement	(467,485)		(68,576)	(90,039)					(626,100)
Payment for bond issuance & financing costs	(3,888)		(699)	(954)			(43)		(5,584)
Capital and nuclear fuel acquisitions	(28,838)				(59)		(15,849)		(44,746)
Interest paid on revenue bonds	(93,123)	(158)	(92,534)	(54,384)			(2,606)		(242,805)
Principal paid on revenue bond maturities		(565)							(565)
Interest paid on Notes	(991)		(453)	(388)					(1,832)
Unclaimed Bearer Bond deposit								406	406
Net cash provided (used) by capital and related financing activities	(102,867)	(723)	(94,225)	(55,182)	(59)	-	(18,498)	406	(271,148)
CASH FLOWS FROM INVESTING ACTIVITIES									
Purchases of investment securities	(1,134,146)	(8,376)	(637,781)	(455,894)	(18,234)	(7,973)	(142,651)	(174,680)	(2,579,735)
Sales of investment securities	1,131,516	8,380	637,199	469,199	15,581	9,046	156,268	176,994	2,604,183
Interest on investments	1,968	31	1,280	921	15	16	252	232	4,715
Receipts from sales of plant assets			6,202						6,202
Net cash provided (used) by investing activities	(662)	35	6,900	14,226	(2,638)	1,089	13,869	2,546	35,365
NET INCREASE (DECREASE) IN CASH	(23,090)	(33)	(3,091)	(7,631)	3	26	(1,555)	2,030	(32,935)
CASH AT JUNE 30, 2003	59,802	6	33,552	27,566	(2)	5	6,078	1,062	128,069
CASH AT JUNE 30, 2004 (NOTE B)	$ 36,712	$ (27)	$ 30,461	$ 19,935	$ 1	$ 31	$ 4,523	$ 3,498	$ 95,134

* Project recorded on a liquidation basis
See notes to financial statements

STATEMENTS OF CASH FLOWS *(Continued)*

For the year ended June 30, 2004 (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	2004 COMBINED TOTAL
RECONCILIATION OF OPERATING INCOME TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES									
Net operating revenues	$ 115,759	$ 124	$ -	$ -	$ (1,057)	$ -	$ (50)	$ -	$ 114,776
Adjustments to reconcile net operating revenues to cash provided by operating activities:									
Cost/cash incurred in excess of cash/cost	(165,623)	(332)							(165,955)
Depreciation and amortization	113,598	333			32		3,223		117,186
Decommissioning	42,993						54		43,047
Other	1,955				51				2,006
Change in operating assets and liabilities:									
Accounts receivable	50	(80)			(1,089)		231		(888)
Materials and supplies	(742)						(226)		(968)
Prepaid and other assets	202	9			(44)		1		168
Due from/to other business units, funds and Participants	(17,823)	596			5,027		(103)		(12,303)
Accounts payable	(9,930)	5			(220)		(56)		(10,201)
Non-operating revenue receipts			95,457	36,234		887			132,578
Cash payments for preservation, termination expense			(11,223)	(2,909)					(14,132)
Cash payments for services						(1,950)		(516)	(2,466)
Net cash provided (used) by operating and other activities	$ 80,439	$ 655	$ 84,234	$ 33,325	$ 2,700	$ (1,063)	$ 3,074	$ (516)	$ 202,848

* Project recorded on a liquidation basis
See notes to financial statements

OUTSTANDING LONG-TERM DEBT

As of June 30, 2004 (Dollars in Thousands)

COLUMBIA (NUCLEAR PROJECT NO. 2) REFUNDING REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
1990A	7.25%	7-1-2006	$ 2,115	
			2,115	
1990C	(C)	7-1-2005	11,590	
			11,590	
1991A	(C)	7-1-2006/2007	10,267	
			10,267	
1992A	6.10	7-1-2006	11,345	
	6.25	7-1-2012	50,000	
			61,345	
1993A	5.50-5.80	7-1-2005/2008	51,295	
			51,295	
1993B	5.40-5.65	7-1-2005/2008	54,725	
			54,725	
1994A	4.80-6.00	7-1-2005/2007	110,160	
	(C)	7-1-2009	4,776	
	5.40	7-1-2012	100,200	
			215,136	
1996A	5.60-6.00	7-1-2005/2012	175,500	
			175,500	
1997A	5.10-5.20	7-1-2010/2012	50,355	
			50,355	
1997B	5.00-5.50	7-1-2005/2011	25,000	
			25,000	
1998A	5.00-5.75	7-1-2005/2012	180,535	
			180,535	
2001A	5.00-5.50	7-1-2013/2017	186,600	
			186,600	
2001B	5.50	7-1-2018	48,000	
			48,000	
2002A	5.20-5.75	7-1-2017/2018	157,260	
			157,260	
2002B	5.35-6.00	7-1-2018	123,815	
			123,815	
2003A	5.50	7-1-2010/2015	154,490	
			154,490	
2003B	4.15	7-1-2009	4,530	
			4,530	
2003F	5.00-5.25	7-1-2007/2018	41,330	
			41,330	
2004A	3.75-5.25	7-1-2008/2018	422,350	
			422,350	
2004B	5.50	7-1-2013	12,715	
			12,715	
2004C	5.25	7-1-2007/2018	26,620	
			26,620	
1997-2A-1	Average Variable .94		48,180	
			48,180	
1997-2A-2	Average Variable .94		48,175	
			48,175	
Compound interest bonds accretion			48,127	
Revenue bonds payable			$ 2,160,055	(B)
Estimated fair value at June 30, 2004			$ 2,414,929	(D)

(A) Includes amounts due July 1, 2004
(B) Excludes amounts due July 1, 2004, which were paid as of June 30, 2004
(C) Compound Interest Bonds
(D) The estimated fair value shown has been reported to meet the disclosure requirements of 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, 2004 (Dollars in Thousands)

PACKWOOD LAKE PROJECT REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES		AMOUNT	
1962	3.625%	3-1-2012	$	2,741	
				2,741	
1965	3.75	3-1-2012		1,010	
				1,010	
Revenue bonds payable			$	3,751	
Estimated fair value at June 30, 2004			$	3,948	(D)

NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES		AMOUNT
1989B	7.125%	7-1-2016	$	41,070
				41,070
1990B	7.25	7-1-2009		3,590
				3,590
1992A	6.10	7-1-2006		720
				720
1993A	5.70-7.00	7-1-2008		34,895
				34,895
1993B	5.15-7.00	7-1-2005/2009		34,650
				34,650
1993C	5.00-5.20	7-1-2008		7,385
				7,385
1996A	5.75-6.00	7-1-2005/2012		324,815
				324,815
1996B	6.00	7-1-2005		765
				765
1996C	5.10-6.00	7-1-2005/2016		83,395
	5.50	7-1-2017		12,740
				96,135
1997A	6.00	7-1-2006/2008		20,400
				20,400
1997B	5.00-5.125	7-1-2005/2017		243,445
				243,445
1998A	5.00-5.75	7-1-2005/2017		85,020
				85,020
2001A	4.125-5.50	7-1-2005/2013		77,160
				77,160

(A) Includes amounts due July 1, 2004
(B) Excludes amounts due July 1, 2004, which were paid as of June 30, 2004
(C) Compound Interest Bonds
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled
(E) 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, 2004 (Dollars in Thousands)

NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
2001B	5.50%	7-1-2017	$ 23,600	(E)
			23,600	
2002A	5.50-5.75	7-1-2013/2017	248,485	
			248,485	
2002B	6.00	7-1-2017	101,950	
			101,950	
2003A	5.50	7-1-2013/2017	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	
1993-1A-1	.95%		47,030	
			47,030	
1993-1A-2	.95%		47,030	
			47,030	
1993-1A-3	.95%		15,410	
			15,410	
2003C	.90%		200,485	
			200,485	
Revenue bonds payable			$ 1,977,325	(A)
Estimated fair value at June 30, 2004			$ 2,211,794	(D)

(A) Includes amounts due July 1, 2004
(B) Excludes amounts due July 1, 2004, which were paid as of June 30, 2004
(C) Compound Interest Bonds
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled
(E) 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, 2004 (Dollars in Thousands)

NUCLEAR PROJECT NO. 3 REFUNDING REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
1989A	(C)	7-1-2005/2014	$ 15,653	
			15,653	
1989B	(C)	7-1-2005/2014	61,379	
	7.125%	7-1-2016	76,145	
			137,524	
1990B	(C)	7-1-2005/2010	19,335	
			19,335	
1993B	5.40-7.00	7-1-2005/2009	53,990	
			53,990	
1993C	5.00-7.50	7-1-2005/2008	73,480	
	(C)	7-1-2013/2018	23,963	
			97,443	
1996A	5.50-6.00	7-1-2005/2009	30,415	
			30,415	
1997A	5.00-6.00	7-1-2005/2018	107,170	
			107,170	
1998A	5.00	7-1-2005	11,150	
	5.125	7-1-2018	53,825	
			64,975	
2001A	5.50	7-1-2010/2018	151,380	
			151,380	
2001B	5.50	7-1-2018	20,675	(E)
			20,675	
2002B	6.00	7-1-2016	75,360	
			75,360	
2003A	5.50	7-1-2011/2017	241,915	
			241,915	
2003B	4.15	7-1-2009	21,575	
			21,575	
2004A	5.25	7-1-2014/2016	83,835	
			83,835	
2004B	5.50	7-1-2013	1,515	
			1,515	
1993-3A-3	.95%		21,325	
			21,325	
1998-3A	.96%		138,650	
			138,650	
2001-B3-1	.98%		5,000	
			5,000	
2003D	.96%		201,065	
			201,065	
2003E	.97%		98,025	
			98,025	
Compound interest bonds accretion			347,965	
Revenue bonds payable			$ 1,934,790	(A)
Estimated fair value at June 30, 2004			$ 2,007,292	(D)

(A) Includes amounts due July 1, 2004
(B) Excludes amounts due July 1, 2004, which were paid as of June 30, 2004
(C) Compound Interest Bonds
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled
(E) Auction Rate Certificates that will have a rate of 5.00 through 7/1/2003, 7/1/2004 (respectively), 5.50 through 7/1/2010, and a variable rate thereafter until 7/1/2018 on the entire 2001B series

OUTSTANDING LONG-TERM DEBT *(Continued)*

As of June 30, 2004 (Dollars in Thousands)

NINE CANYON WIND PROJECT REVENUE BONDS

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
2001A	4.00-6.00%	7-1-2004/2023	$ 50,410	
			50,410	
2001B	4.30-6.00	7-1-2004/2023	20,265	
			20,265	
2003	3.00-5.00	7-1-2005/2023	21,720	
			21,720	
Revenue bonds payable			$ 92,395	(A)
Estimated fair value at June 30, 2004			$ 103,386	(D)

(A) Includes amounts due July 1, 2004
(B) Excludes amounts due July 1, 2004, which were paid as of June 30, 2004
(C) Compound Interest Bonds
(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled
(E) Auction Rate Certificates that will have a rate of 5.00 through 7/1/2003, 7/1/2004 (respectively), 5.50 through 7/1/2010, and a variable rate thereafter until 7/1/2018 on the entire 2001B series

DEBT SERVICE REQUIREMENTS

As of June 30, 2004 (Dollars in Thousands)

COLUMBIA GENERATING STATION

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2004			
Balance:*	$ -	$ 21,651	$ 21,651
2005	101,885	141,953	243,838
2006	94,046	125,966	220,012
2007	153,686	115,427	269,113
2008	143,305	100,543	243,848
2009	134,726	94,496	229,222
2010-2014	799,525	295,146	1,094,671
2015-2018	684,755	120,772	805,527
Adjustment **	48,127	(48,127)	-
	$ 2,160,055	$ 967,827	$ 3,127,882

* Principal and Interest due July 1, 2004

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

PACKWOOD LAKE PROJECT

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2004			
Balance:	$ 197	$ 46	$ 243
2005	598	130	728
2006	624	108	732
2007	648	85	733
2008	673	63	736
2009	572	15	587
2010-2012	439	44	483
Adjustment **			
	$ 3,751	$ 491	$ 4,242

* Principal and Interest due July 1, 2004

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

DEBT SERVICE REQUIREMENTS *(Continued)*

As of June 30, 2004 (Dollars in Thousands)

NUCLEAR PROJECT NO. 1

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2004			
Balance:*	$ -	$ 45,456	$ 45,456
2005	56,510	100,178	156,688
2006	77,890	97,064	174,954
2007	64,575	92,659	157,234
2008	79,000	88,988	167,988
2009	86,710	84,243	170,953
2004-2014	768,205	345,884	1,114,089
2015-2017	844,435	101,424	945,859
Adjustment **			
	$ 1,977,325	$ 955,896	$ 2,933,221

* Principal and Interest due July 1, 2004

** 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
6/30/2004			
Balance:*	$ -	$ 26,511	$ 26,511
2005	64,471	99,357	163,828
2006	65,392	97,862	163,254
2007	60,176	98,330	158,506
2008	63,330	95,337	158,667
2009	68,433	94,684	163,117
2010-2014	345,702	417,485	763,187
2015-2018	919,321	166,715	1,086,036
Adjustment **	347,965	(347,965)	-
	$ 1,934,790	$ 748,316	$ 2,683,106

* Principal and Interest due July 1, 2004

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

DEBT SERVICE REQUIREMENTS *(Continued)*

As of June 30, 2004 (Dollars in Thousands)

NINE CANYON WIND PROJECT

FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL
6/30/2004			
Balance:*	$ 2,060	$ 2,460	$ 4,520
2005	2,915	4,835	7,750
2006	3,040	4,720	7,760
2007	3,170	4,594	7,764
2008	3,315	4,457	7,772
2009	3,480	4,301	7,781
2010-2014	20,290	18,713	39,003
2015-2019	26,630	12,592	39,222
2020-2023	27,495	4,076	31,571
Adjustment **			
	$ 92,395	$ 60,748	$ 153,143

* Principal and Interest due July 1, 2004

** 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 created in 1957. It is empowered to finance, acquire, construct, and operate facilities for the generation and transmission of electric power. On June 30, 2004, 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 separately 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). In Fiscal Year 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.

Energy Northwest also manages the Business Development Fund, Nine Canyon Wind Project, and 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 Fiscal Year 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 Fiscal Year 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 50 MW 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 intentions of completing the facility with its own funds. Energy Northwest and DENA have a contract for site preservation services during this construction suspension time period. Per the agreement with DENA, if construction is 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 dissolution of the contract.

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.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Energy Northwest has adopted accounting policies and principles that are in accordance with accounting principles generally accepted in the United States of America. 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 2004 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 Standards 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 accounting principles generally accepted in the United States of America 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 Project, Energy Northwest’s policy is to capitalize all costs relating to the Project, including interest expense (net of interest income), and related administrative and general expense.

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 Fiscal Year 1995 and is 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, 2004, was as follows:

Utility Plant Activity *(Amount in Thousands)*

	BEGINNING BALANCE	INCREASES	DECREASES	ENDING BALANCE
Columbia				
Generation	$ 3,452,528	$ 492	$ (1,663)	$ 3,451,357
Decommission	31,110	-	-	31,110
Construction Work-in-Progress	13,987	16,514	-	30,501
Accumulated Depreciation	(1,865,096)	(78,034)	-	(1,943,130)
Accumulated Amortization	(9,861)	(519)		(10,380)
Utility Plant, net	$ 1,662,668	$ (61,547)	$ (1,663)	$ 1,559,458
Nine Canyon				
Generation	$ 48,029	$ 20,006	$ -	$ 68,036
Decommission	449	-	-	449
Construction Work-in-Progress	3,965	-	(3,965)	-
Accumulated Depreciation	(1,622)	(2,955)	-	(4,578)
Accumulated Amortization	(8)	(29)	-	(37)
Utility Plant, net	$ 50,813	$ 17,022	$ (3,965)	$ 63,870
Packwood				
Generation	$ 12,991	$ -	$ -	$ 12,991
Accumulated Depreciation	(12,083)	(334)	-	(12,417)
Utility Plant, net	$ 908	$ (334)	$ -	$ 574
Business Development				
General	$ 823	$ 59	$ -	$ 882
Accumulated Depreciation	(214)	(32)	-	(246)
Utility Plant, net	$ 609	$ 27	$ -	$ 636
Internal Service Fund				
General	$ 43,837	$ -	$ -	$ 43,837
Construction Work-in-Progress	$ -	515		$ 515
Accumulated Depreciation	(29,124)	(1,482)	-	(30,606)
Utility Plant, net	$ 14,713	$ (967)	$ -	$ 13,746

Nuclear Fuel

All expenditures related to the purchase of nuclear fuel for Columbia, including interest, are 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 $132.4 million as of June 30, 2004, 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 $9.0 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 periodically to allow for future refuelings. Current period operating costs include $33.6 million for nuclear fuel and $1.7 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, 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.

Asset Retirement Obligation

Energy Northwest adopted the Statement of Financial Accounting Standards No. 143, Accounting for Obligations Associated with the Retirement of Long-Lived Assets (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: Accounting for Asset Retirement Obligations, for discussion regarding the impact of adopting SFAS 143.)

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, 2003.

Energy Northwest's current estimate of Columbia's decommissioning costs is approximately $608 million (in 2003 dollars). This estimate, which is updated bi-annually, 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 EFSEC on June 12, 1995. Energy Northwest's current estimate of Columbia's site restoration costs is approximately $65 million (based on a 2003 study) and is updated bi-annually with the decommissioning estimate.

Both decommissioning and site restoration estimates (in the 2003 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, 2004, totaled approximately $83.9 million and $9.4 million, respectively, and are included as a Deferred Charge on the Balance Sheet. 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 of revenue bonds payable from restricted assets are reflected in Long-Term Debt for the Packwood project. For all other projects, debt that matures in the next twelve months is reflected as current maturities of Long-Term Debt.

Accounts Payable and Accrued Expenses

Restricted Liabilities – Internal Service Fund accounts payable and accrued expenses include $0.4 million for unclaimed bearer bonds. Columbia includes $90.7 million for decommissioning and site restoration. Nuclear Project No. 1 includes $26.2 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 $0.7 million for payroll and related benefits, $16 million for compensated absences, and $1.5 million for outstanding warrants. The Nine Canyon Wind Project includes retainage related to construction in the amount of $0.1 million.

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 enables the Nine Canyon Wind Project to receive funds based on generation as it applies to the REPI bill. 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 77 percent of the applied REPI funding in the amount of $1.5 million for Fiscal Year 2004. The payment stream and REPI receipts were projected to cover the total costs over 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.

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, and 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.

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, 2004, 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 following).

AVAILABLE-FOR-SALE INVESTMENTS *(Dollars in Thousands)*

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
Columbia				
U.S. Government Agencies	40,747	0	(8)	40,739
Total	40,747	0	(8)	40,739
Packwood				
U.S. Government Securities	2,789	0	(1)	2,788
Total	2,789	0	(1)	2,788
Nuclear Project No. 1				
U.S. Government Agencies	54,178	0	(2)	54,176
Total	54,178	0	(2)	54,176
Nuclear Project No. 3				
U.S. Government Agencies	29,357	0	(1)	29,356
Total	29,357	0	(1)	29,356
Business Development Fund				
U.S. Government Agencies	3,552	0	(1)	3,551
Total	3,552	0	(1)	3,551
CT Project				
U.S. Government Agencies	1,135	0	0	1,135
Total	1,135	0	0	1,135
Internal Service Fund				
U.S. Government Agencies	23,638	0	(8)	23,630
Total	23,638	0	(8)	23,630
Nine Canyon Wind				
U.S. Government Securities	758	0	(1)	757
U.S. Government Agencies	10,688	0	(2)	10,686
Total	11,446	0	(3)	11,443

AVAILABLE-FOR-SALE INVESTMENTS *(Continued)*

(Dollars in Thousands)

	< 1 year	1-5 years	5-10 years	> 10 years	Total
Columbia					
U.S. Government Agencies	40,739	0	0	0	40,739
Total	40,739	0	0	0	40,739
Packwood					
U.S. Government Securities	2,788	0	0	0	2,788
Total	2,788	0	0	0	2,788
Nuclear Project No. 1					
U.S. Government Agencies	54,176	0	0	0	54,176
Total	54,176	0	0	0	54,176
Nuclear Project No. 3					
U.S. Government Agencies	29,356	0	0	0	29,356
Total	29,356	0	0	0	29,356
Business Development Fund					
U.S. Government Agencies	3,551	0	0	0	3,551
Total	3,551	0	0	0	3,551
CT Project					
U.S. Government Agencies	1,135	0	0	0	1,135
Total	1,135	0	0	0	1,135
Internal Service Fund					
U.S. Government Agencies	23,631	0	0	0	23,630
Total	23,631	0	0	0	23,630
Nine Canyon Wind					
U.S. Government Securities	757	0	0	0	757
U.S. Government Agencies	10,686	0	0	0	10,686
Total	11,443	0	0	0	11,443

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 Retirement 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, 2004, were:

	PERS Plan 1	*PERS Plan 2*	*PERS Plan 3*
*Employer**	*1.4%*	*1.4%*	*1.4%***
Employee	*6.00%*	*1.18%*	***

*The employer rates include the employer administrative expense fee currently set at 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 year ended June 30 were:

	PERS Plan 1	*PERS Plan 2*	*PERS Plan 3*
2004	*$101,132*	*$905,073*	*$336,973*
2003	*$108,239*	*$1,077,106*	*$95,821*
2002	*$147,307*	*$1,238,861*	*N/A*

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. One hundred and one 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, 2004, was $1.035 million for these benefits.

During Fiscal Year 2004, 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 90 percent of all such costs were allocated to Columbia during Fiscal Year 2004.

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 percent of the portion of the participant's salary deferral amount, which does not exceed 5 percent 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 Fiscal Year 2004, Energy Northwest contributed $1.8 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, 2004, Energy Northwest issued, for Nuclear Projects 1, 3, and Columbia, the Series 2004-A Bonds, Series 2004-B Bonds, Series 2004-C Bonds. The Series 2004-A 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 5.23 percent. The Series 2004-A Bond Proceeds of $606.4 million refunded $606.4 million of outstanding bonds having a weighted average coupon interest rate of 5.31 percent. The $606.4 million of proceeds associated with the Series 2004-A Bonds were allocated to Nuclear Project No. 1 ($66.9 million), Columbia ($450.6 million), and Nuclear Project No. 3 ($88.9 million). This transaction resulted in a net gain for accounting purposes of $0.9 million for Nuclear Project 1, a net gain of $1.2 million for Nuclear Project 3, and a net gain of $3.4 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 2004-B Bonds, issued for Nuclear Project No.1, Nuclear Project No. 3, and Columbia, in the aggregate amount of $15.4 million, are taxable fixed rate bonds with a weighted average coupon interest rate of 5.5 percent. The 2004-B Bond Proceeds were used for the purpose of paying costs relating to the issuance of the Series 2004-A and Series 2004-B Bonds, as well as certain costs relating to the refunding of certain outstanding bonds. Lastly, some of the Series 2004-B Bond Proceeds will be used to finance a portion of the cost of certain capital improvements.

The Series 2004-C Bonds, issued for Columbia, in the amount of $26.6 million, are fixed rate bonds with an average coupon interest rate of 5.25 percent. The Series 2004-C Bonds were issued to finance a portion of the costs of certain capital improvements at Columbia, and to pay costs relating to the issuance of the Series 2004-C Bonds.

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 Fiscal Year 2004 defeasements, approximately $260.9 million, $101.8 million, and $201.3 million of defeased bonds were not called or had not matured at June 30, 2004, for Nuclear Projects Nos. 1, 3, and Columbia, respectively.

Outstanding revenue bonds for the various Business Units as of June 30, 2004, and future debt service requirements for these bonds are presented at the end of the Financial Section of this report.

Security - Nuclear Projects Nos. 1, 3, and Columbia

Project Participants have purchased all of the capability of Nuclear Projects Nos. 1, 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 Fiscal Year 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 run through October 30, 2004. A subsequent one-year extension was negotiated for the period beginning November, 1, 2004, extending through October 30, 2005. Benton and Franklin County PUDs agree to pay Energy Northwest in exchange for the total output of electric capacity and energy delivered from the Packwood Project. 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 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 SRP introduced legislation with the State of Washington under Senate Bill No. 6427, which passed and was signed by the Governor of the State of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 and Nuclear Project No. 5 exists for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights. In February 1999, Energy Northwest entered into a transfer agreement with the SRP to transfer the real and personal property at the site of Nuclear Project No. 3 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 Fiscal Year 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 percent interest in NoaNet with an additional 25 percent step-up possible for a maximum 9.23 percent. As of June 30, 2004, NoaNet has $26.0 million in outstanding bonds. 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) the Business Development Fund could be required to pay is $2.4 million. 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 Fiscal Year 2004, the Business Development Fund contributed $0.3 million 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 $13.1 million. Future equity contributions, if any, will be treated the same until NoaNet has a positive equity position.

Business Development Fund Enriched Uranium Lease Transaction

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 percent per annum (through June 30, 2006) on the market value of the leased enriched uranium. In accordance with Emerging Issues Task Force (EITF) No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent," the lease revenues and expenses are presented on a net basis in the statement of operations as the Business Development Fund does not take title to the enriched uranium, does not have inventory risk, and is at risk only for the net margin. For Fiscal Year 2004, 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 $2.25 billion. The deductible for this coverage is $5.0 million per occurrence.

NOTE G – ACCOUNTING CHANGE: 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 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 costs in excess of billings. An adjustment was made in Fiscal Year 2004 adjusting the accretion rate from the original model and calculation. This adjustment increased the liability by $42.0 million for Columbia Generating Station. As of June 30, 2004, Columbia Generating Station has a net asset value of $20.7 million and an accumulated liability of $90.7 million. Nuclear Project No. 1 has an accumulated liability of $26.2 million.

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 Fiscal Year 2003. As of June 30, 2004, the Nine Canyon Wind Project has an accumulated liability of $0.5 million.

The following table describes the changes to Energy Northwest's ARO liabilities for the year ended June 30, 2004:

	Millions of dollars
Columbia	
Balance at 6/30/03	$47.7
Adjustment to cumulative accretion	38.5
Current year accretion expense	4.5
ARO at 6/30/04	$90.7
Nuclear Project No. 1	
Balance at 6/30/03	$25.9
Adjustment to cumulative accretion	0.7
Less: Restoration costs incurred	(1.2)
Accretion Expense	1.3
Adjustment to estimated timing of cash flows	(0.5)
ARO at 6/30/04	$26.2
Nine Canyon Wind Project	
Balance at 6/30/03	$ 0.47
Current year accretion expense	0.03
ARO at 6/30/04	$ 0.50

Packwood's obligation has not been calculated because the timeframe 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 these assets will be used in utility operations for the foreseeable future.

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL

Preston|Gates|Ellis LLP

Energy Northwest

Citigroup Global Markets Inc.

Goldman, Sachs & Co.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Seattle-Northwest Securities Corporation

UBS Financial Services Inc.

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 [$72,175,000/$114,985,000/$129,265,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue Refunding Bonds, Series 2005-A and Series 2005-B (Taxable) (the "2005 Bonds"). The 2005 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "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 May 19, 2005 (the "Supplemental Resolution"). The 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 2005-A Bonds are [not] subject to redemption in the manner and upon the terms and conditions set forth in the Bond Resolutions. The Series 2005-B Bonds are not subject to redemption prior to their stated maturity. The 2005 Bonds rank junior as to security and payment to bonds issued and outstanding under the Prior Lien Resolution. The 2005 Bonds rank equally as to security and payment with all other Parity Debt.

In connection with the issuance of the 2005 Bonds, we have examined a certified transcript of all of the proceedings taken in the matter of the issuance of the 2005 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 2005 Bonds and apply the proceeds of the 2005 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 2005 Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2005 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 2005 Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2005 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 2005 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

Citigroup Capital Markets

Goldman, Sachs & Co.

J.P. Morgan Securities Inc.

Prager, Sealy & Co., LLC

Seattle-Northwest Securities Corporation

UBS Financial Services Inc.

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 [$72,175,000/$114,985,000/$129,265,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue Refunding Bonds, Series 2005-A and Series 2005-B (Taxable) (the "2005 Bonds"). The Series 2005 Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [838/1042/838] (the "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 May 19, 2005 (the "Supplemental Resolution"). The 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 2005 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 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 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 Agreement 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
$72,175,000 Project 1 Energy Northwest Revenue Refunding Bonds, Series 2005-A
$114,985,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A
$129,265,000 Project 3 Energy Northwest Revenue Refunding Bonds, Series 2005-A
$925,000 Project 1 Energy Northwest Revenue Refunding Bonds, Series 2005-B (Taxable)
$1,600,000 Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable)
$1,060,000 Project 1 Energy Northwest Revenue Refunding Bonds, Series 2005-B (Taxable)

Ladies and Gentlemen:

We have acted as Special Tax Counsel 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 $72,175,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2005-A (the "Project 1 2005-A Bonds"), $114,985,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-A (the "Columbia 2005-A Bonds"), $129,265,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2005-A (the "Project 3 2005-A Bonds," and together with the Project 1 2005-A Bonds and the Columbia 2005-A Bonds, the "Series 2005-A Bonds"), $925,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Project 1 2005-B Taxable Bonds"), $1,600,000 aggregate principal amount of Columbia Generating Station Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Columbia 2005-B Taxable Bonds") and $1,060,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2005-B (Taxable) (the "Project 3 2005-B Taxable Bonds," and together with the Project 1 2005-B Taxable Bonds and the Columbia 2005-B Taxable Bonds, the "Series 2005-B Taxable Bonds"). The Project 1 2005-A Bonds and the Project 1 2005-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 May 19, 2005 (the "Project 1 Resolution"). The Columbia 2005-A Bonds and the Columbia 2005-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 a supplemental resolution adopted on May 19, 2005 (the "Columbia Resolution"). The Project 3 2005-A Bonds and the Project 3 2005-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 May 19, 2005 (the "Project 3 Resolution," and together with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Series 2005-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest. The Series 2005-B Taxable Bonds are being issued for the purpose of paying certain costs of issuance and other refunding costs relating to the Series 2005-A Bonds and the Series 2005-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 2005-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 2005-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 2005-A Bonds and Series 2005-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 2005-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 2005-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 May 19, 2005, relating to the Series 2005-A Bonds and Series 2005-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 2005-A Bonds and the Series 2005-B Taxable Bonds and with respect to the due authorization and issuance of the Series 2005-A Bonds and Series 2005-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 2005-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 "Code"). We also are of the opinion that interest on the Series 2005-B Taxable Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act and Section 103 of the Code. Interest on the Series 2005-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 2005 Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE
AMENDED FISCAL YEAR 2005 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 2005 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.

"*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 2005 Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2005 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 Credit Markets Services ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

"Refunded Municipal Obligations" shall mean obligations of any state, the District of Columbia or possession of the United States of America or any political subdivision thereof, which obligations are rated in the highest rating category by at least two nationally recognized rating agencies and provision for the payment of the principal of and interest on which shall have been made by deposit with a Trustee or escrow agent of direct obligations of, or obligations guaranteed by, the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or any state, the District of Columbia or possession thereof in the capacity as custodian, the maturing principal of and interest on which when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession or political subdivision.

"*Reserve Account Requirement*" shall mean, with respect to a Series of Electric Revenue Bonds, the amount, if any, prescribed by the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Reserve Guaranty*" shall mean an insurance policy or surety bond provided by an insurer whose claims-paying ability is rated in either of the two highest rating categories by at least two nationally recognized rating agencies, or a letter of credit or other similar Credit Facility the long-term unsecured debt of the issuer of which is rated in either of the two highest rating categories by at least two nationally recognized rating agencies.

"Revenues" shall mean all income, revenues, receipts and profits derived by Energy Northwest through the ownership and operation by Energy Northwest of the related Project and all other moneys required to be deposited in the Revenue Fund 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.

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 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 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 2005-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.

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 Participants (as hereinafter defined).

DTC will act as securities depository for the 2005 Bonds. The 2005 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 2005 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 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 2005 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 2005 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 2005 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 2005 Bonds, except in the event that use of the book entry-entry system for the 2005 Bonds is discontinued.

To facilitate subsequent transfers, all 2005 Bonds deposited by Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of 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 2005 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 2005 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 2005 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 2005 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 Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the 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 2005 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 Participant or to any person on behalf of whom a Participant holds an interest in the 2005 Bonds with respect to (i) the accuracy of the records of DTC, Cede & Co. or any Participant with respect to any ownership interest in the 2005 Bonds; (ii) the delivery to any Participant or any other person, other than a bondowner as shown on the Bond Register, of any notice with respect to the 2005 Bonds, including any notice of redemption; (iii) the payment to any 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 2005 Bonds; (iv) the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the 2005 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 Participant acquires an interest in the 2005 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 2005 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 2005 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 2005 Bonds in the table labeled: "Energy Northwest Revenue Bonds Outstanding as of April 1, 2005" 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 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, and to the Bond Insurers, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2005:

(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, and to the Bond

Insurers, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with Energy Northwest Fiscal Year ending June 30, 2005:

(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 2005 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 2005-A Bonds;

(vii) Modifications to rights of 2005 Bondholders;

(viii) Optional, contingent or unscheduled calls of any 2005 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 2005 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 2005 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 2005 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 2005

Bonds; and (ii) notifies each then existing NRMSIR and the SID, if any (or transmitting entity approved by the SEC), 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 2005 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 2005 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 2005 Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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Ambac

Financial Guaranty Insurance Policy

Ambac Assurance Corporation
One State Street Plaza, 15th Floor
New York, New York 10004
Telephone: (212) 668-0340

Obligor: Policy Number:

Obligations: Premium:

Ambac Assurance Corporation (Ambac), a Wisconsin stock insurance corporation, in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to The Bank of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of the Holders, that portion of the principal of and interest on the above-described obligations (the "Obligations") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor.

Ambac will make such payments to the Insurance Trustee within one (1) business day following written notification to Ambac of Nonpayment. Upon a Holder's presentation and surrender to the Insurance Trustee of such unpaid Obligations or related coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Holder the amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, Ambac shall become the owner of the surrendered Obligations and/or coupons and shall be fully subrogated to all of the Holder's rights to payment thereon.

In cases where the Obligations are issued in registered form, the Insurance Trustee shall disburse principal to a Holder only upon presentation and surrender to the Insurance Trustee of the unpaid Obligation, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee duly executed by the Holder or such Holder's duly authorized representative, so as to permit ownership of such Obligation to be registered in the name of Ambac or its nominee. The Insurance Trustee shall disburse interest to a Holder of a registered Obligation only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Obligation and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee, duly executed by the Holder or such Holder's duly authorized representative, transferring to Ambac all rights under such Obligation to receive the interest in respect of which the insurance disbursement was made. Ambac shall be subrogated to all of the Holders' rights to payment on registered Obligations to the extent of any insurance disbursements so made.

In the event that a trustee or paying agent for the Obligations has notice that any payment of principal of or interest on an Obligation which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from the Holder pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such Holder will be entitled to payment from Ambac to the extent of such recovery if sufficient funds are not otherwise available.

As used herein, the term "Holder" means any person other than (i) the Obligor or (ii) any person whose obligations constitute the underlying security or source of payment for the Obligations who, at the time of Nonpayment, is the owner of an Obligation or of a coupon relating to an Obligation. As used herein, "Due for Payment", when referring to the principal of Obligations, is when the scheduled maturity date or mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity; and, when referring to interest on the Obligations, is when the scheduled date for payment of interest has been reached. As used herein, "Nonpayment" means the failure of the Obligor to have provided sufficient funds to the trustee or paying agent for payment in full of all principal of and interest on the Obligations which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Obligations prior to maturity. This Policy does not insure against loss of any prepayment or other acceleration payment which at any time may become due in respect of any Obligation, other than at the sole option of Ambac, nor against any risk other than Nonpayment.

In witness whereof, Ambac has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

Robert J Genader
President

AMBAC ASSURANCE CORPORATION
CORPORATE
SEAL
WISCONSIN

Anne G. Gill
Secretary

Effective Date:

Authorized Representative

THE BANK OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Noraida Lauro
Authorized Officer of Insurance Trustee

Form No.: 2B-0012 (1/01)

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